

# MEETING THE DUAL CHALLENGE

A Roadmap to At-Scale Deployment of  
CARBON CAPTURE, USE, AND STORAGE

## CHAPTER SEVEN – CO<sub>2</sub> GEOLOGIC STORAGE



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## Chapter Seven

# CO<sub>2</sub> GEOLOGIC STORAGE

### I. CHAPTER SUMMARY

Storing carbon dioxide (CO<sub>2</sub>) in deep geologic formations, for the purpose of reducing greenhouse gas (GHG) emissions, began in 1996 with the Sleipner CO<sub>2</sub> storage project in Norway. When Equinor (formerly Statoil) began pumping 1 million tonnes per annum (Mtpa) of CO<sub>2</sub> into the offshore Utsira Formation in the Sleipner gas field, it paved the way for three additional large-scale projects in Norway, the United States, and Canada. These projects collectively have stored approximately 4 Mtpa. In 2019, the Gorgon Project in Western Australia initiated injection operations into a saline formation, and when at full operation in 2020, will store between 3 to 4 Mtpa. More than 20 years after the Sleipner project was established, there is now an extensive network of global knowledge about CO<sub>2</sub> storage, and the United States has emerged as a world leader on the topic. As of 2019, there are currently 19 large-scale carbon capture, use, and geologic storage (CCUS) projects operating around the world with a total storage volume of about 32 Mtpa. Ten of these projects are in the United States, accounting for a total storage volume of 25 Mtpa.

Safe, secure, and permanent geologic storage of CO<sub>2</sub> requires the presence of a sufficiently permeable rock formation, typically sandstone or carbonate, which is sealed by rocks on top that have a very low permeability. These formations need to be 1 kilometer (km) or deeper to ensure that the CO<sub>2</sub> is stored as a dense phase, also called a supercritical fluid. To protect underground drinking water aquifers, CO<sub>2</sub> storage is only permitted in saline formations that are saltier than

10,000 parts per million (ppm) total-dissolved-solids per the United States Environmental Protection Agency (EPA) Class VI Underground Injection Control (UIC) regulations. The geologic seal, typically a shale formation, must be continuous over the entire area where the CO<sub>2</sub> is stored and free of defects such as permeable faults, fractures, or leaky wellbore penetrations.

The CO<sub>2</sub> storage capacity estimates for the United States have been assessed by both the United States Department of Energy (DOE) and the United States Geological Survey (USGS). Both assessments indicate a very large potential for storage, with median estimates ranging from 3,000 to 8,600 billion metric tons (called gigatonnes or Gt) of CO<sub>2</sub>. The economic potential, often referred to as a “storage reserve” is likely to be significantly lower, but how much lower is not known yet. Even conservative estimates are very large compared to the ~5 Gt CO<sub>2</sub>/year emitted in the United States—of which about 50% or ~2.5 Gt CO<sub>2</sub>/year is associated with large-scale stationary emissions sources—suggesting that storage capacity is unlikely to be a limiting factor in the United States. Other factors, such as access to CO<sub>2</sub> pipelines for transport, capture economics, public support, and local injectivity constraints, are likely to pose a greater challenge to at-scale deployment of CCUS in the United States.

Prospective geologic formations for CO<sub>2</sub> storage require adequate storage capacity, sufficient permeability, and a high-quality geologic seal. Additional considerations include an assessment of the risks of induced seismicity and the potential for CO<sub>2</sub> or brine leakage through preexisting

boreholes. Brine is another term for saline water that naturally exists in a rock formation.

Cost estimates that include both capital expenditures and operating costs for storage in saline formations range from \$1 to \$18 per tonne of CO<sub>2</sub> (tCO<sub>2</sub>) in 2013 dollars. For most sites in the United States, DOE estimates narrow the range from \$7 to \$13/tCO<sub>2</sub>. The wide range reflects the site-specific nature of geologic storage projects. In 2019, preliminary cost estimates for storage sites in the Southeastern United States, which has excellent geologic conditions for storage, were as low as \$3/tCO<sub>2</sub>.<sup>1</sup> Storage cost is primarily affected by the depth of the formation, volume of CO<sub>2</sub> to be stored, number of injection wells required, purity of the CO<sub>2</sub> stream, existing land uses, and ease of deploying surface and subsurface CO<sub>2</sub> monitoring programs.

In the United States, underground storage of CO<sub>2</sub> is regulated by the EPA's UIC Program. Regulations for Class VI CO<sub>2</sub> storage wells were finalized in 2010. Six permits have been issued, but only two permits are active, both in Illinois, and only one of those permits is currently in active injection operations. Four permits were issued for the FutureGen 2.0 project in Illinois, but these were never used because the project was funded through the American Reinvestment and Recovery Act, which expired in 2015 before the project could be completed.

This chapter explains the following topics:

- Description of CO<sub>2</sub> geologic storage
- Current knowledge about geologic storage, including its costs and existing projects
- Geologic storage options and capacities in conventional and unconventional onshore conventional offshore formations, and depleted oil and natural gas fields
- Description of what is needed to enable at-scale deployment including incentives, access to onshore federal lands and offshore leases, and clarifying legal issues

- Issues that affect both CO<sub>2</sub> enhanced oil recovery (EOR) and CO<sub>2</sub> geologic storage
- Research and development needed to accelerate CO<sub>2</sub> storage.

In 2018, the National Academies of Science, Engineering, and Medicine completed a report on the key research needs associated with negative emissions technologies and secure sequestration (storage) of CO<sub>2</sub>.<sup>2</sup> This chapter also acknowledges the findings from that report.

## II. WHAT IS CO<sub>2</sub> GEOLOGIC STORAGE?

### A. Describing CO<sub>2</sub> Storage

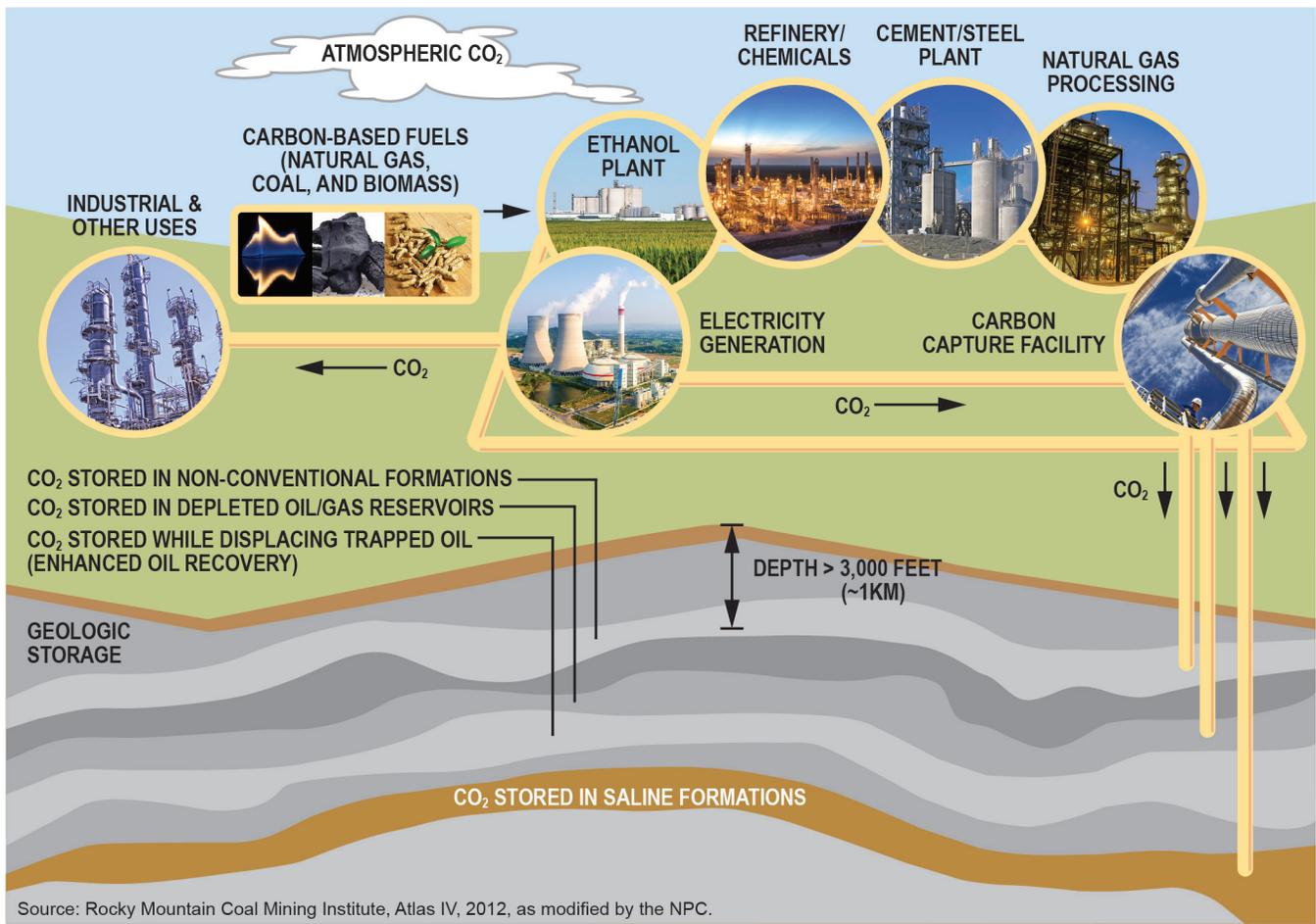
Carbon capture, use, and storage, including transport, combines processes and technologies to reduce the level of CO<sub>2</sub> emitted to the atmosphere or remove CO<sub>2</sub> from the air. These technologies work together to capture (separate and purify) CO<sub>2</sub> from stationary sources so that it can be compressed and transported to a suitable location where the CO<sub>2</sub> is converted into usable products or injected deep underground for safe, secure, and permanent storage. Figure 7-1 is a schematic showing the CCUS technologies.

Geologic storage refers to the process by which CO<sub>2</sub> is pumped underground into rocks such that it is permanently trapped so it cannot return to the atmosphere. The key to achieving this is identifying geologic formations that have two specific properties.

First, the formation rock must have sufficient pore space (porosity) in which CO<sub>2</sub> can be contained for storage and pathways connecting the pore space (permeability) so the CO<sub>2</sub> can be injected into and move within the formation. About 73% of the rocks on the Earth's surface meet these criteria. These are sedimentary rocks that were formed when small grains of sediment accumulated on seashores, deltas, ocean floors, riverbeds, and lakes over millions of years. Eventually the sediments were buried and became sandstone, which is largely

1 Esposito, R. A., Kuuskraa, V. A., Rossman, C. G., and Corser, M. C., "Reconsidering CCS in the U.S. fossil-fuel fired electricity industry under section 45Q tax credits," *Greenhouse Gas Science & Technology*, 0:1–14 (2019), doi: 10.1002/ghg.1925.

2 National Academies of Sciences, Engineering, and Medicine. (2019). *Negative Emissions Technologies and Reliable Sequestration: A Research Agenda*. Washington, DC: The National Academies Press: <https://doi.org/10.17226/25259>.

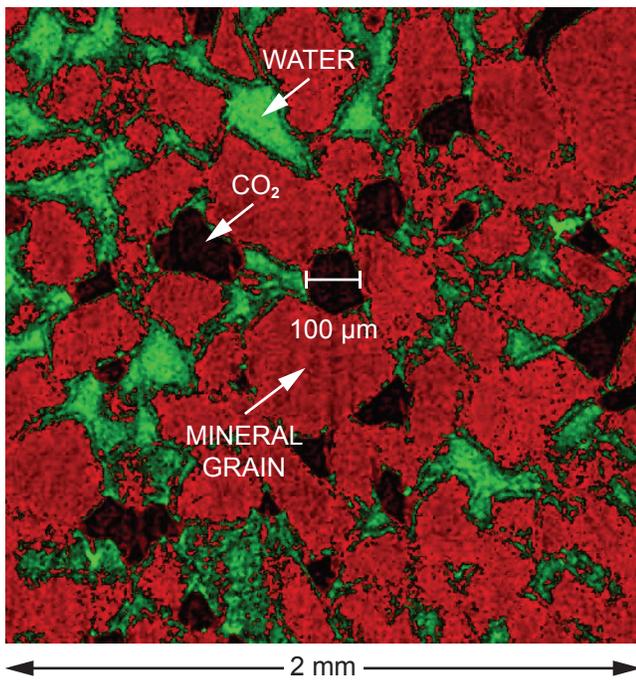


**Figure 7-1.** Supply Chain for Carbon Capture, Use, and Storage

composed of quartz grains, or carbonates, which results from the accumulation of small marine organisms and shells. Although sandstones and carbonates appear to be solid rock, they are filled with small void spaces called pores. When these types of rock are about a mile or more below the surface, under normal conditions the pores are filled with salty water, which is why they are called saline formations. Pushing the water out of the way, and filling the pore spaces with CO<sub>2</sub> instead, enables the storage of large volumes of CO<sub>2</sub>. Figure 7-2 shows a microscopic image of the rocks in a saline formation storing CO<sub>2</sub>. The rock grains are red, pore spaces filled with water are green, and pore spaces filled with CO<sub>2</sub> are black. Typically, 10% to 25% of the rock volume is made up of pores. A discussion of the potential capacity for storing CO<sub>2</sub> in sandstone and carbonate rocks is found in Section IIIA, Storage Options in Conventional Geologic Formations.

The storage formations must be deep enough so that the natural pressure and temperature can maintain the CO<sub>2</sub> as a dense fluid, also called a supercritical fluid or state. Typically, the minimum depth required for this temperature and pressure are greater than or equal to about 3,000 feet (about 1 kilometer or 0.56 miles) depending on geothermal gradient. To protect underground drinking water aquifers, CO<sub>2</sub> storage is only permitted in saline formations that are saltier than 10,000 ppm Total Dissolved Solids (TDS) per EPA Class VI UIC regulations.

Second, a prospective storage reservoir must have a geologic seal above it. The sedimentary rock of a geologic seal must have a very low permeability that prevents CO<sub>2</sub> from leaving the storage formation. Seals are often made up of clay (shale), salt, or carbonate rocks with pores that are too small to enable the CO<sub>2</sub> to enter or pass through them.



Source: Silin, D., Tomutsa, L., Benson, S. M., and Patzek, T. W. (2011). "Microtomography and pore-scale modeling of two-phase fluid distribution." *Transport in Porous Media*, 86 (2), 495-515.

**Figure 7-2.** Microscopic Image of Sandstone Showing Mineral Grains and Pore Spaces Filled with Water or CO<sub>2</sub>

When CO<sub>2</sub> is injected into the formation rock, it displaces some of the saline water—also called brine—in the formation, causing the reservoir’s fluid pressure to increase. The pressure buildup increases the density of the brine and pore volume of the rock, making space in the reservoir to accommodate the incoming volume of CO<sub>2</sub>. The magnitude of pressure buildup depends on the CO<sub>2</sub> injection rate, rock properties such as permeability, and the size of the storage reservoir. For large reservoirs with high permeability, the pressure buildup is small and does not present any storage safety concerns by damaging the reservoir and causing CO<sub>2</sub> leakage. In contrast, in a small, completely sealed reservoir, the pressure buildup may be rapid and large. A large pressure buildup would damage the geologic seal that sits on top of the storage formation, preventing fluids from escaping the reservoir. Avoiding damage to this seal requires limiting the rate of injection or extracting some of the displaced brine while the CO<sub>2</sub> injection is taking place. When CO<sub>2</sub> injection stops, reservoir pres-

sure will gradually decrease until it returns to its pre-injection level.

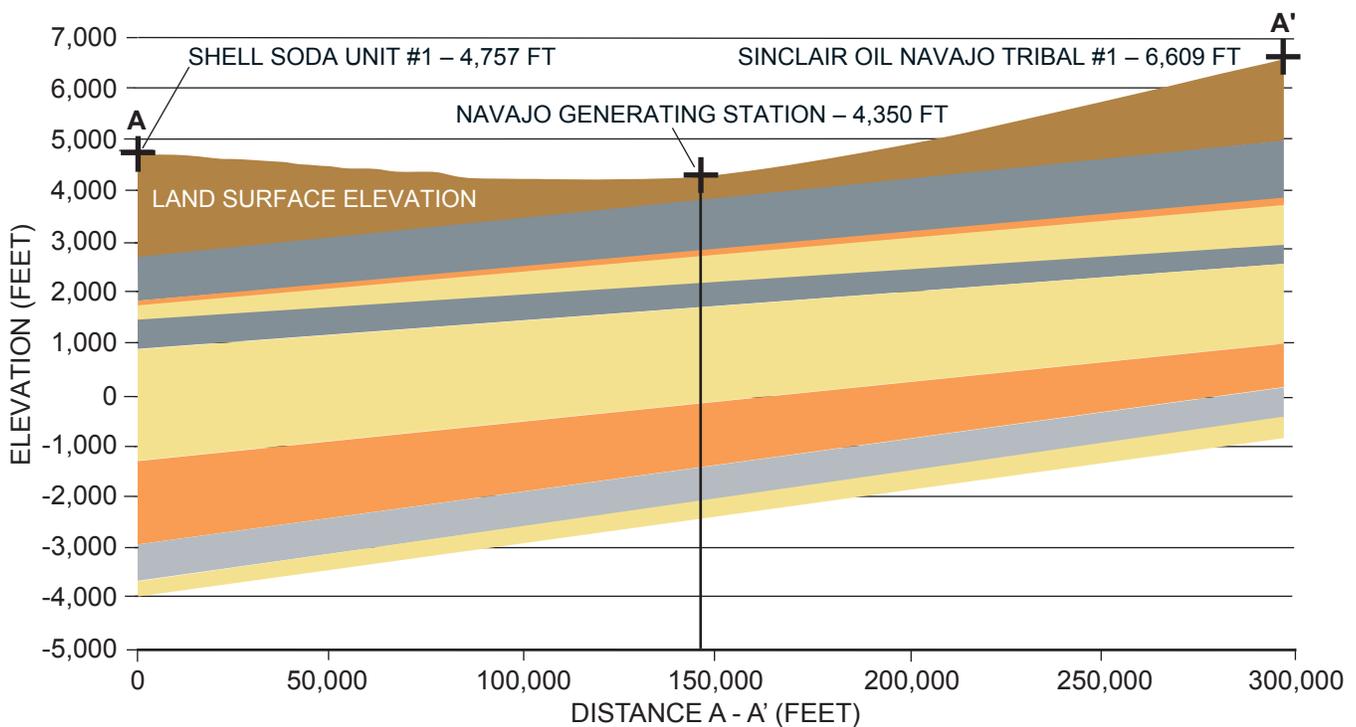
Sandstone reservoirs with alternating layers of porous and permeable rock, sitting below a low-permeability geologic seal(s), are ideal for storing large volumes of CO<sub>2</sub> (Figure 7-3) because of their layered geology. These types of formations occur naturally and are rather prolific in the United States. When CO<sub>2</sub> storage operators select a reservoir, the goal is to identify one that has enough storage capacity (volume) to accommodate all the CO<sub>2</sub> that needs to be stored and has an extensive seal to ensure safe, secure, and permanent storage.

The Earth’s naturally occurring geology provides the oldest proof that large quantities of CO<sub>2</sub> can be safely and securely trapped underground for millions of years. In 2005, the United Nations Intergovernmental Panel on Climate Change concluded that, “The widespread presence of oil, gas, and CO<sub>2</sub> trapped in formations for many millions of years implies that within sedimentary basins, impermeable formations—called caprocks—of sufficient quality to confine CO<sub>2</sub> for geologic time periods are present.”<sup>3</sup> And in Mississippi, the CO<sub>2</sub> trapped in the Pisgah Anticline northeast of the Jackson Dome is thought to have been emplaced more than 65 million years ago.<sup>4</sup> This example is one among several deposits of natural CO<sub>2</sub> that exist in the United States and around the world, demonstrating that naturally occurring reservoir seals exist and are able to confine CO<sub>2</sub> for millions of years.

When compared to millions of years, the 100 years of intentional, underground storage of gases and liquids due to human activities is a relatively recent development. Humans have been storing natural gas securely in depleted oil and natural gas reservoirs and other formations for more than 40 years. Natural gas storage reservoirs are also good analogues for CO<sub>2</sub> storage and demonstrate that injected gas can be

<sup>3</sup> United Nations Climate Change Conference (2005) in Montreal, Quebec, Canada.

<sup>4</sup> Studlick, J. R. J., Shew, R. D., Basye, G. E., and Ray, J. R. (1990). “A giant carbon dioxide accumulation in the Norphlet Formation, Pisgah Anticline, Mississippi,” 181-203, in Barwis, J. H., McPhearson, J. G. and Studlick, J. R. J. (eds.), *Sandstone Petroleum Reservoirs*, Springer-Verlag, New York.



Source: Benson, S. M. and Cole, D. R. (2008). "CO<sub>2</sub> Sequestration in Deep Sedimentary Formations." *Elements*, vol. 4, pp. 325-331.

**Figure 7-3.** *The Layered Geology of Sandstone (yellow) Below Shale Seals (grey) that Enables CO<sub>2</sub> Storage*

stored underground safely. Natural gas storage is used as a buffer between natural gas supply and demand. In 2019, there were more than 400 natural gas storage facilities operating in the United States and Canada with a total storage capacity exceeding 160 Mt.<sup>5</sup>

## B. CO<sub>2</sub> Storage Projects Around the Globe

There have been several CCUS research programs conducted in Europe, the United States, Canada, Australia, and Japan since 1990. The global body of knowledge about CO<sub>2</sub> storage has been gleaned from these early commercial and demonstration carbon capture and storage (CCS) projects, including:

- Sleipner project, Norway: ~1 Mtpa stored, began in 1996
- Snøhvit project, Norway: ~0.8 Mtpa stored, began in 2008
- Frio pilot, United States: ~1.6 kilotonnes (Kt) stored 2004–2009
- Illinois-Decatur project, United States: ~1 Mtpa stored 2011–2014
- In Salah project, Algeria: ~1 Mtpa stored 2004–2011
- Ketzin project, Germany: ~70 Kt stored 2008–2014
- Plant Barry CCS project, United States: ~115 Kt stored 2012–2014
- Otway project, Australia: 15 Kt stored 2015–2016
- Aquistore project, Canada: ~110 Kt stored 2015–2017
- Lacq project, France: 51 Kt stored 2010–2013
- Tomakomai project, Japan: ~200 Kt stored 2016–2018
- Quest project, Canada: 1 Mtpa stored since 2015
- Illinois Industrial project, United States: 1 Mtpa stored since 2017

<sup>5</sup> Metz, B., Davidson, O., de Coninck, H., Loos, M., and Meyer, L. (eds.), *Carbon Capture and Storage*, IPCC, 2005 – Special Report, Cambridge University Press, UK, p. 431.

- Gorgon LNG project, Australia: injection operations started in 2019, increasing to 3 to 4 Mtpa in 2020.

International collaborations facilitated by organized networks such as the IEA Greenhouse Gas R&D Programme, Global CCS Institute, Carbon Sequestration Leadership Forum, and CO<sub>2</sub>GeoNet were instrumental to creating a global scientific community dedicated to CO<sub>2</sub> storage.

### C. Commercial CO<sub>2</sub> Injection Projects

Injection of CO<sub>2</sub> in the subsurface began in the 1960s with CO<sub>2</sub> EOR operations, many of which were in the United States. CO<sub>2</sub> injection is a common process applied in several industries, including oil and natural gas production, natural gas and hydrogen storage, municipal wastewater disposal, waste management, geothermal energy production, and aquifer recharge. The CO<sub>2</sub> injection process used across different industries is based on similar concepts and technologies and addresses similar technical and non-technical challenges.

Commercial storage projects in deep saline formations around the globe include Snøhvit in the North Sea and Aquistore in Canada, which operate at lower injection rates or intermittently. Chevron began CO<sub>2</sub> injection at the Gorgon Project on Barrow Island off the coast of Western Australia in 2019. When the project reaches full capacity of 3 to 4 Mtpa in 2020, it will be the largest commercial storage project in the world. Another commercial-scale operation that is no longer actively injecting CO<sub>2</sub> is the In Salah project in Algeria.

The projects highlighted in this section include offshore (Sleipner in Norway) and onshore (Illinois Industrial CCS and Quest in Canada) saline formation storage examples. The CO<sub>2</sub> for these projects is sourced from a variety of industrial activities, including natural gas processing, bioethanol fermentation, and heavy oil upgrading. Each project injects about 1 Mtpa of CO<sub>2</sub> into sandstone reservoirs.

#### 1. Sleipner CCUS Project, Norway

Commercial CO<sub>2</sub> storage in deep saline formations was first implemented at the Sleipner CCUS

project in Norway in 1996.<sup>6</sup> Sleipner is an offshore, platform-based CO<sub>2</sub> capture facility that is part of the Sleipner gas and condensate field development located approximately 155 miles (250 km) offshore southern Norway. The CO<sub>2</sub> stream at Sleipner is derived from natural gas processing and uses a solvent-based absorption, post-combustion capture process that is explained in Chapter 5, “CO<sub>2</sub> Capture.” The Sleipner project has integrated commercial-scale CCUS with conventional oil and natural gas field development operations.

The CO<sub>2</sub> is injected and stored in the Utsira Formation about 0.6 mile (1 kilometer) below the seabed. By 2018, the Sleipner project had stored more than 17 Mt of CO<sub>2</sub> at an average annual injection rate of about 0.9 Mt/year. More recently, the Sleipner project began storing CO<sub>2</sub> captured from neighboring gas fields, giving it CCUS hub status.<sup>7</sup> Monitoring storage site performance and assuring safe containment through monitoring has been achieved through a series of time-lapse seismic data sets. These data sets provide important insights into the value and detection capabilities of remote geophysical monitoring methods.<sup>8</sup> The 23-year performance history at Sleipner is a testament to the value of careful well design and engineering.

#### 2. Illinois Industrial Carbon Capture Project

The Illinois Industrial Carbon Capture and Storage project (IL-ICCS), led by the Archer Daniels Midland Company (ADM), is demonstrating an integrated system for collecting and geologically storing up to 3,000 tonnes/day of CO<sub>2</sub> from ADM’s bioethanol plant in Decatur, Illinois. The CO<sub>2</sub> is captured at atmospheric pressure and high

6 Baklid, A., Korbol, R., and Owren, G. (1996). “Sleipner Vest CO<sub>2</sub> disposal, CO<sub>2</sub> injection into a shallow underground aquifer.” In *SPE Annual Technical Conference and Exhibition*, Society of Petroleum Engineers.

7 Ringrose, P. S. (2018). “The CCS hub in Norway: some insights from 22 years of saline aquifer storage,” *Energy Procedia*, vol. 146, 166-172.

8 Chadwick, A., Williams, G., Delepine, N., Clochard, V., Labat, K., Sturton, S., and Arts, R., “Quantitative analysis of time-lapse seismic monitoring data at the Sleipner CO<sub>2</sub> storage operation,” *The Leading Edge*, 29(2) (2010): 170-177.

purity—greater than 99% purity on a moisture-free basis—from ADM’s corn-to-ethanol fermenters. The CO<sub>2</sub> stream is compressed, dehydrated, and delivered by an 8-inch diameter, 1-mile long pipeline to the injection wellhead.

The IL-ICCS project holds the first EPA UIC permit to operate a Class VI injection well. Injection of CO<sub>2</sub> at the IL-ICCS project uses a single injection well and began injection operations in April 2017. The site was designed to inject 3,000 tonne/day to meet an annual storage target of 1 Mt. The monitoring of injected CO<sub>2</sub> is performed within the Mount Simon Sandstone injection zone and above the storage reservoir by verification wells using geophysical surveys, pressure-temperature (P/T) sensors, and geochemical sampling. Shallow, environmental monitoring is ongoing and includes assessing groundwater via geochemical sampling and P/T monitoring, soil resistivity, and near-infrared aerial imagery.

### 3. Quest Project, Alberta Canada

The Quest Project owned by Shell Canada captures CO<sub>2</sub> produced at the Scotford Upgrader near Edmonton and then compresses, transports by pipeline, and injects the CO<sub>2</sub> for permanent onshore storage in a saline formation near Thorhild, Alberta. Shell completed drilling three wells about 1.2 miles (1.9 km) deep during 2012 and 2013 for the injection operations phase of the project. Injection began in two of the wells in 2015. Up to 1.2 Mtpa of CO<sub>2</sub> is being captured and there has been limited pressure buildup within the reservoir. Post-injection startup, monitoring, and verification activities have shifted to operational monitoring. Monitoring data indicates that no CO<sub>2</sub> has migrated outside of the injection reservoir to date.

## III. STORAGE OPTIONS

Geologic storage of CO<sub>2</sub> requires injecting captured CO<sub>2</sub> into a subsurface formation that has enough porosity and permeability to store and transmit fluids. In addition, CO<sub>2</sub> needs to be injected into reservoirs where it can be permanently contained to prevent migration above and beyond the storage area.

In this study, CO<sub>2</sub> storage reservoirs are divided into conventional and unconventional reservoirs. Conventional formations have rock and fluid characteristics that enable gas and fluid to easily flow to or from wellbores drilled into the formation. The rock types that typically facilitate this include sandstone, limestone, dolomite, or a mixture of these rock types.<sup>9</sup>

Unconventional formations include a collection of rock types such as shale, and low-permeability (tight) sandstones, and some carbonates. Other possible subsurface CO<sub>2</sub> storage options include coal beds and basaltic and ultramafic rocks. Table 7-1 estimates the total technical storage capacity by type of formation in the United States, which was developed as part of DOE and USGS investigations. Median estimates for the technical storage potential in the United States range from about 3,000 to 8,600 Gt CO<sub>2</sub>.<sup>10</sup>

The values in Table 7-1 are the technical potential for storing CO<sub>2</sub> and do not consider economic factors, risks of induced seismicity, or other constraints on the practicality of injecting CO<sub>2</sub> at commercial rates. Practical estimates of storage capacity were developed that considered whether sufficiently high rates of injection could be achieved, the proximity to faults, a lack of surface access, and if the presence of very thin sands makes injection more costly. Figure 7-4 illustrates the impact of each factor on reducing the practical storage capacity that could be available. The two most significant factors are reductions caused by limitations on the injection rate (40% reduction) and the presence of thin sands (20% reduction).

9 Benson, S. et al. (2005). “Underground geologic storage,” in Metz, B., Davidson, O., de Coninck, H., Loos, M., and Meyer, L., eds., *Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Dioxide Capture and Storage*, Cambridge, UK: Cambridge University Press, p. 195–276, <https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/>.

10 U.S. Department of Energy, National Energy Technology Laboratory. (2015). *Carbon Storage Atlas* (5th ed.; Atlas V) (DOE/NETL-2015/1709): 113 p., <https://www.netl.doe.gov/research/coal/carbon-storage/natcarb-atlas>.

U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). “National assessment of geologic carbon dioxide storage resources—Results” (ver. 1.1, September 2013), U.S. Geological Survey Circular 1386, 41 p., <http://pubs.usgs.gov/circ/1386/>.

Type of Geologic Formation	Low (Gt CO <sub>2</sub> )	Median (Gt CO <sub>2</sub> )	High (Gt CO <sub>2</sub> )	Source(s)
Conventional Onshore	2,379	8,328	21,633	National Energy Technology Laboratory (NETL) Carbon Storage Atlas (2015)*
	2,300	2,984	3,700	USGS (2013)†
Conventional Offshore	n/a	n/a	1,000	Southern States Energy Board (2013)‡
Shale	28§	134¶	171#,**	Nuttall et al. (2005),§ Godec et al. (2013a),¶ Godec et al. (2013b)#
Coal Beds	54	80	113	NETL Carbon Storage Atlas (2015)*
Basalt	n/a	n/a	n/a	
Depleted Oil and Natural Gas Reservoirs	190		230	NETL Carbon Storage Atlas (2015)*

\* U.S. Department of Energy, National Energy Technology Laboratory. (2015). Carbon Storage Atlas (5th ed.; Atlas V) (DOE/NETL-2015/1709): 113 p., <https://www.netl.doe.gov/research/coal/carbon-storage/natcarb-atlas>.

† U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). "National assessment of geologic carbon dioxide storage resources—Results." (ver. 1.1, September 2013): U.S. Geological Survey Circular 1386, 41 p., <http://pubs.usgs.gov/circ/1386/>.

‡ Southern States Energy Board. (2013). "Preliminary Evaluation of Offshore Transport and Geologic Storage of Carbon Dioxide," <https://www.sseb.org/wp-content/uploads/2010/05/Offshore-Study-full2.pdf>.

§ Nuttall, B. C., Eble, C. F., Drahovzal, J. A., and Bustin, M. R. (2005). Analysis of Devonian black shales in Kentucky for potential carbon dioxide sequestration and enhanced natural gas production: Kentucky Geological Survey Final Report to U.S. Department of Energy, 120 p.

¶ Godec, M. L., Jonsson, H., and Basava-Reddi, L. (2013a). "Potential global implications of gas production from shales and coal for geological CO<sub>2</sub> storage." *Energy Procedia*, vol. 37, 6656-6666.

# Godec, M., Koperna, G., Petrusak, R., and Oudinot, A. (2013b). "Assessment of factors influencing CO<sub>2</sub> storage capacity and injectivity in eastern U.S. gas shales," GHGT-11, *Energy Procedia*, vol. 37, 6644-6655.

\*\* Benson, S., et al. (2005). "Underground geologic storage," in Metz, B., Davidson, O., de Coninck, H., Loos, M., and Meyer, L., eds., Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Dioxide Capture and Storage, Cambridge, UK: Cambridge University Press. p. 195–276, <https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/>.

**Table 7-1. Storage Capacity Estimates for Different Geologic Formations in the United States**

Although practical storage capacity estimates are lower than previously published technical estimates, onshore subsurface storage capacity in the United States is enough to sustain a large-scale CO<sub>2</sub> storage industry. Different types of formations have different technical and practical storage capacity estimates due to differing reservoir properties. It is estimated that approximately 500 Gt of storage capacity in the United States is practically available today in reasonable proximity to CO<sub>2</sub> emissions sources or transport infrastructure<sup>11</sup> (see Chapter 2, "CCUS Supply Chains and Economics," in Volume II of this report).

11 Teletzke, G. F., Palmer, J. J., Druempel, E., Sullivan, M. B., Hood, K. C., Dasari, G. R., and Shipman, G. W. (2018). "Evaluation of Practicable Subsurface CO<sub>2</sub> Storage Capacity and Potential CO<sub>2</sub> Transportation Networks, Onshore North America," GHGT-14, Melbourne, Australia.

## A. Storage Options in Conventional Geologic Formations

### 1. Definition of Conventional Reservoirs

After CO<sub>2</sub> is captured, it needs to be compressed into a dense, liquid-like state called a supercritical fluid so it can be transported and injected into a formation. Compressing the captured CO<sub>2</sub> gas to a supercritical fluid enables more CO<sub>2</sub> to be stored because it has a higher density compared with gaseous CO<sub>2</sub>.<sup>12</sup> In the United States, fresh subsurface sources of drinking water are protected by the Safe Drinking Water Act.

12 Benson, S., et al. (2005). "Underground geologic storage," in Metz, B., Davidson, O., de Coninck, H., Loos, M., and Meyer, L., eds., Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Dioxide Capture and Storage, Cambridge, UK: Cambridge University Press. p. 195–276, <https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/>.

To be suitable for conventional storage of CO<sub>2</sub>, the geologic formations must have an impermeable regional seal or series of seals (Figures 7-1 and 7-3). CO<sub>2</sub> in a supercritical fluid state is less dense than the fluids that initially fill the pore spaces in the rock. Hence after injection, the CO<sub>2</sub> slowly rises by buoyancy forces through the reservoir rocks until it encounters a low-permeability primary geologic seal. The sealing formations prevent CO<sub>2</sub> stored in the reservoirs from migrating into shallower groundwater aquifers, or to the surface where it could be released to the atmosphere. Once trapped below the primary seal, the CO<sub>2</sub> will remain permanently stored unless a mobile CO<sub>2</sub> plume encounters a permeable fault or fracture in the seal or a leaky wellbore.<sup>13</sup> However, this type of complication has not occurred at any of the CO<sub>2</sub> storage sites listed in the section on CO<sub>2</sub> Storage Projects around the globe, and careful site selection is the reason why it has not. Although primary geologic seals are important

to retaining injected CO<sub>2</sub> underground, there are other mechanisms for immobilizing CO<sub>2</sub> to prevent leakage.

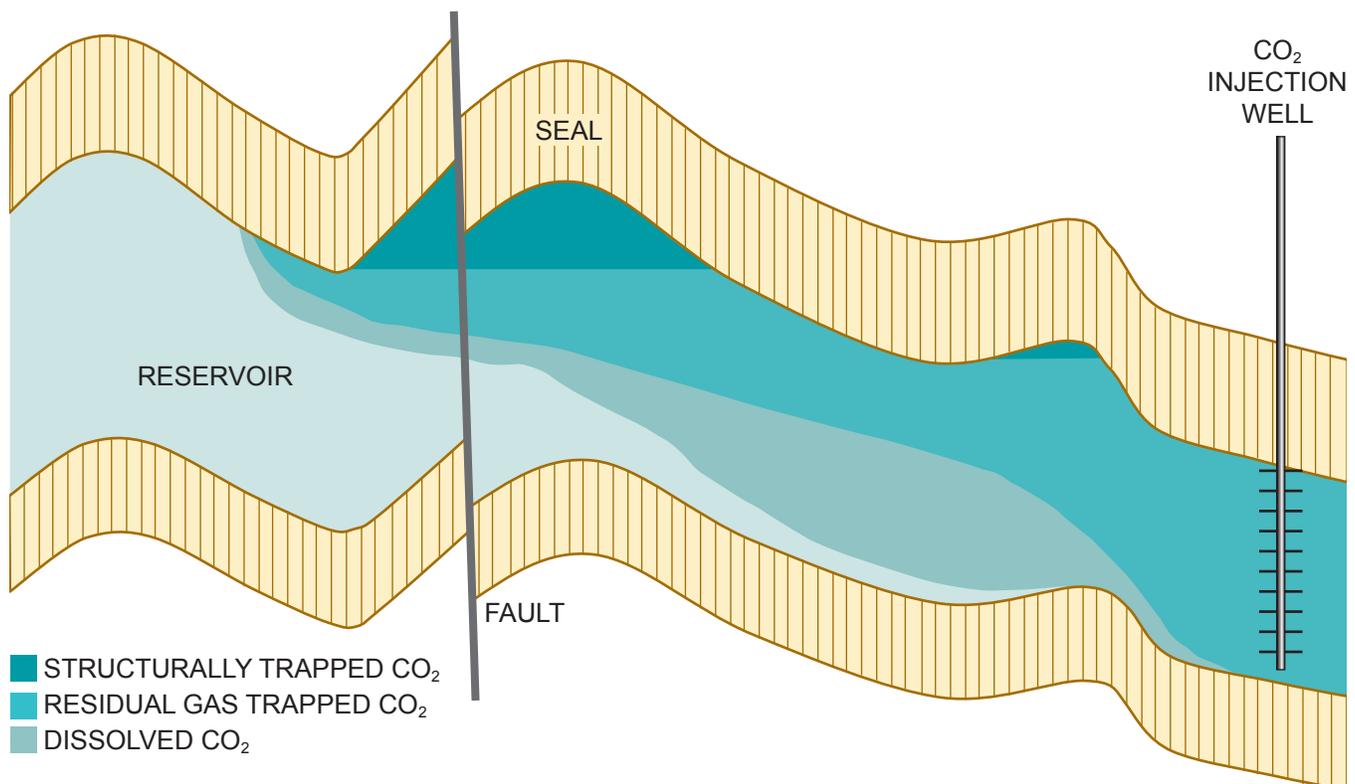
## 2. CO<sub>2</sub> Trapping in Conventional Reservoirs

Storage of CO<sub>2</sub> in conventional formations can use one of several trapping processes—buoyant, residual, solubility, and mineral.<sup>14</sup> In buoyant trapping, CO<sub>2</sub> generally flows upward slowly until it is immobilized in a stratigraphic or structural trap formed by the geologic seal (also called caprock), lateral seals, sealing faults, or other seals (Figure 7-4).<sup>15</sup> Residual trapping occurs as small droplets of CO<sub>2</sub> are left behind during the migration of a CO<sub>2</sub> plume through the porous reservoir rock. These droplets are trapped in the

13 National Academies of Sciences, Engineering, and Medicine. (2018). *Negative Emissions Technologies and Reliable Sequestration: A Research Agenda*. Washington, DC: The National Academies Press, 356 p., <https://org/10.17226/25259>.

14 Benson, S. M., and Cole, D. R. (2008). "CO<sub>2</sub> Sequestration in Deep Sedimentary Formations," *Elements*, vol. 4, pp. 325-331, doi: 10.2113/gselements.4.5.325.

15 Brennan, S. T., Burruss, R. C., Merrill, M. D., Freeman, P. A., and Ruppert, L. F. (2010). "A probabilistic assessment methodology for the evaluation of geologic carbon dioxide storage," U.S. Geological Survey Open-File Report 2010-1127, <http://pubs.usgs.gov/of/2010/1127>.



**Figure 7-4.** How CO<sub>2</sub> Is Trapped in a Storage Formation

rock's pore spaces by interfacial (surface) tension. Solubility trapping dissolves 10% to 25% of the CO<sub>2</sub> almost instantly when it is injected into the formation. When injection stops, the CO<sub>2</sub> will continue to dissolve very slowly due to the convective mixing of dissolved CO<sub>2</sub> with the brine in the storage formation. For siliciclastic<sup>16</sup> (sandstone) reservoirs with a significant fraction of calcium, magnesium, and iron-rich minerals (e.g., feldspar and clay minerals), CO<sub>2</sub> mineral trapping may also occur over time (from years to decades) when the injected CO<sub>2</sub> dissolves into the reservoir fluids and reacts with the formation rock.

The minimum depth requirement of 3,000 feet (>900 meters) for a storage formation ensures that CO<sub>2</sub> is compressed in a supercritical state, which minimizes storage volume. CO<sub>2</sub> can be stored at depths greater than 13,000 feet (>4,000 meters) if favorable reservoir conditions exist. The lateral limit of the storage formation is defined by the location where the top of the storage formation reaches the defined depth limit.<sup>17</sup>

Mineral trapping is generally considered to be the slowest form of trapping in sandstone reservoirs. However, injection projects in the Columbia River and in Iceland have indicated that mineralization of CO<sub>2</sub> in basalts can take place much faster than previously believed—on the order of years. These findings have been documented in a 2013 USGS report<sup>18</sup> and by the projects themselves.

### 3. CO<sub>2</sub> Storage Resource Estimates for Conventional Reservoirs

National assessments of CO<sub>2</sub> storage resources have been conducted by several organizations. Most notable is the 2013 assessment by the USGS Geological Carbon Dioxide Storage Resources Assessment Team, and one in 2015 by the DOE's National Energy Technology Laboratory (NETL).

<sup>16</sup> Benson and Cole. (2008).

<sup>17</sup> Blondes, M. S. et al. (2013). "National assessment of geologic carbon dioxide storage resources—Methodology implementation: U.S. Geological Survey Open-File Report 2013–1055, <http://pubs.usgs.gov/of/2013/1055/>.

<sup>18</sup> U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). "National assessment of geologic carbon dioxide storage resources—Results" (ver. 1.1, September 2013): U.S. Geological Survey Circular 1386, <http://pubs.usgs.gov/circ/1386/>.

These assessments indicate that the United States may have mean or median total technical storage resources ranging from 3,000 to 8,600 Gt.

However, not all these resources are available for storing CO<sub>2</sub> due to reservoir pressure management considerations if large-scale CO<sub>2</sub> injection and storage is adopted nationwide (Figure 7-5).<sup>19</sup> Revised CO<sub>2</sub> storage resource estimates that include reservoir pressure management considerations is an area of ongoing research. Beyond overall regional storage capacity estimates, significant work has been performed with site-specific source-to-sink capacity estimates between Alabama Power's Plant Barry and Citronelle Dome.<sup>20</sup>

The injectivity calculation in Figure 7-5 assumes that wells are far enough apart to avoid any pressure interference between the wells. If the wells are closer together, pressure interference between wells may limit injectivity.<sup>21</sup> As such, the injection capacity per well and storage capacity per basin cited should be considered maximum values. In addition, these represent average values for an entire formation; within a given formation, injectivity will be higher and lower than the values shown.

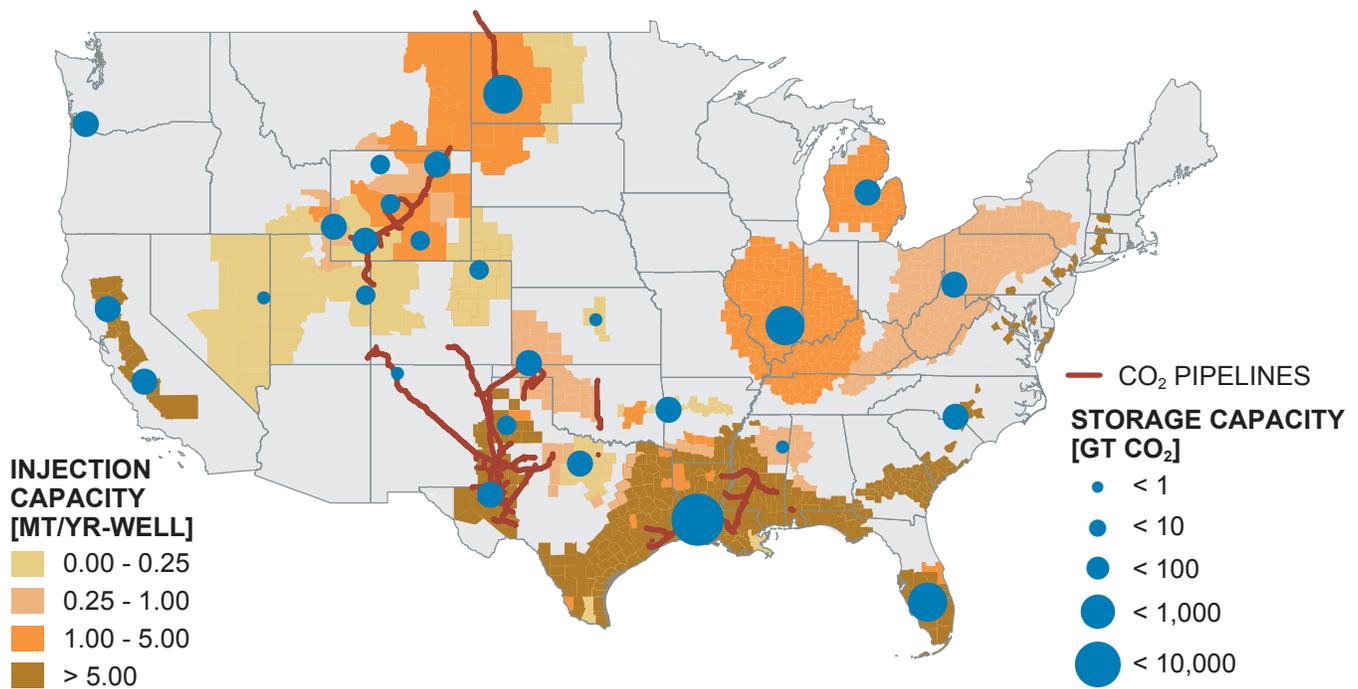
### 4. Challenges Associated with Storage Projects in Conventional Reservoirs

In 2018, the National Academies of Sciences, Engineering, and Medicine (NAEM) noted that in order to meet GHG reduction goals and limit the impact on global temperatures, the nations of the world need to capture and store at least 5 to 10 Gt of CO<sub>2</sub> per year in deep sedimentary formations. Besides the enormous infrastructure scale-up issues associated with such an

<sup>19</sup> Baik, E. et al. (2018). "Geospatial analysis of near-term potential for carbon-negative bioenergy in the United States." *Proceedings of the National Academy of Sciences*, 115(13), 3290–3295.

<sup>20</sup> Esposito, R. A., Pashin, J. C., and Walsh, P. M., "Citronelle Dome: A Giant Opportunity for Multi-Zone Carbon Storage and Enhanced Oil Recovery in the Mississippi Interior Salt Basin of Alabama," *Environmental Geosciences*, 2008, 15(2), 1–10.

<sup>21</sup> Jahediesfanjani, H., Warwick, P. D., and Anderson, S. T. (2018). "Estimating the pressure-limited CO<sub>2</sub> injection and storage capacity of the United States saline formations—Effect of the presence of hydrocarbon reservoirs," *International Journal of Greenhouse Gas Control*, v. 79, p. 14–24, <https://doi.org/10.1016/j.ijggc.2018.09.011>.



Source: Baik, E., et al. (2018). "Geospatial analysis of near-term potential for carbon-negative bioenergy in the United States." *Proceedings of the National Academy of Sciences*, 115(13), 3290-3295.

**Figure 7-5.** CO<sub>2</sub> Injectivity per Well and Storage Capacity in the United States

undertaking, more research is needed to better manage how CO<sub>2</sub> storage projects in the same basin would interact with each other, both the CO<sub>2</sub> plumes and resulting pressure buildup (see Figure 7-9 in the Research and Development Needs section later in this chapter). Some of the research topics associated with geologic storage projects that NASEM identified in the 2018 report include:

- Quantifying and managing the risks of induced seismicity associated with subsurface injection of CO<sub>2</sub>
- Increasing CO<sub>2</sub> injection site selection and characterization methods
- Improving the effectiveness of CO<sub>2</sub> injection site monitoring and lowering costs for monitoring and CO<sub>2</sub> storage verification
- Improving performance of trapping mechanisms and accelerating speed in trapping CO<sub>2</sub>
- Developing reservoir engineering approaches for co-optimizing CO<sub>2</sub> EOR and associated CO<sub>2</sub> storage
- Assessing and managing risk in compromised or leaky CO<sub>2</sub> storage systems

- Improving simulation models for CO<sub>2</sub> storage performance prediction and confirmation
- Social sciences research for improving stakeholder engagement and informing the public about the need, opportunity, risks, and benefits of CO<sub>2</sub> storage in geologic formations.

## 5. Storage Costs in Conventional Formations

Costs for CO<sub>2</sub> storage have been estimated based on existing projects and cost models for various scenarios.<sup>22</sup> Estimates range from \$1 to \$18 per tCO<sub>2</sub> in 2013 dollars (Table 7-2). The most recent estimates from DOE in 2014 narrow the range from \$7 to \$13 per tCO<sub>2</sub>, but several projects in the southeastern United States have documented total storage costs in the range of \$3 to \$6 per tCO<sub>2</sub>.<sup>23</sup> The wide range reflects the highly

22 Rubin, E. S., Davidson, J. E., and Herzog, H. J. (2015). "The Costs of CO<sub>2</sub> Capture and Storage," *International Journal of Greenhouse Gas Control*, <http://dx.doi.org/10.1016/j.ijggc.2015.05.018>.

23 Esposito, R. A., Kuuskraa, V. A., Rossman, C. G., and Corser, M. C. (2019). "Reconsidering CCS in the U.S. fossil-fuel fired electricity industry under section 45Q tax credits," *Greenhouse Gas Science & Technology*, 0:1–14 (2019); DOI: 10.1002/ghg.1925.

Study	Low Estimate (2013\$/tCO <sub>2</sub> )	High Estimate (2013\$/tCO <sub>2</sub> )
United Nations Intergovernmental Panel on Climate Change (2005)	1	12
Zero Emission Platform (2011)	2	18
U.S. Department of Energy (2014)	7	13
Global Carbon Capture Storage Institute (2011)	6	13

Source: Rubin, E. S., Davidson, J. E., Herzog, and H. J., "The Cost of CO<sub>2</sub> Capture and Storage," *International Journal of Greenhouse Gas Control*, September 2015.

**Table 7-2. Total Costs for CO<sub>2</sub> Storage in Geologic Formations from Different Studies**

site-specific nature of geologic storage projects. Primary variables include the depth of the formation, number of injection wells required, existing land uses, and ease of deploying monitoring programs. Costs include well drilling, injection, monitoring, maintenance, reporting, land acquisition and permits, and other incidental costs. They do not include costs associated with remediation activities that may be required in the case of well leakage, groundwater contamination, or managing the risks of induced seismicity with active pressure management.<sup>24</sup> Proper design and operations should avoid these complications, thus the costs associated with remediation are not included in these estimates.

In 2017, the NETL developed the FE/NETL CO<sub>2</sub> Saline Storage Cost Model, an open-source spreadsheet model for estimating the cost of storing CO<sub>2</sub> in saline formations.<sup>25</sup>

24 Kuuskraa, V. A. (January 1, 2009). "Cost-Effective Remediation Strategies for Storing CO<sub>2</sub> in Geologic Formations." Society of Petroleum Engineers. doi:10.2118/126618-MS.

Zahasky, C., and Benson, S.M., "Evaluation of hydraulic controls for leakage intervention in carbon storage reservoirs," *International Journal of Greenhouse Gas Control*, vol. 47, 2016, p. 86-100.

Brunner, L., and Neele, F., "MiReCOL – A Handbook and Web Tool of Remediation and Corrective Actions for CO<sub>2</sub> Storage Sites," *Energy Procedia*, vol. 114, 2017, p. 4203-4215.

25 National Energy Technology Laboratory. (2017). "FE/NETL CO<sub>2</sub> Storage Cost Model," U.S. Department of Energy, <https://edx.netl.doe.gov/dataset/fe-netl-co2-saline-storage-cost-model-2017>.

It is important to note that in the United States under the current EPA UIC Class VI regulatory regime for CO<sub>2</sub> storage, the storage operator must demonstrate financial assurance that certain specific activities can be conducted even if the operator were to become financially insolvent. These specific activities include being able to close injection wells properly at the end of CO<sub>2</sub> injection and to perform post-injection site monitoring and closure activities.

## B. Storage in Unconventional Reservoirs

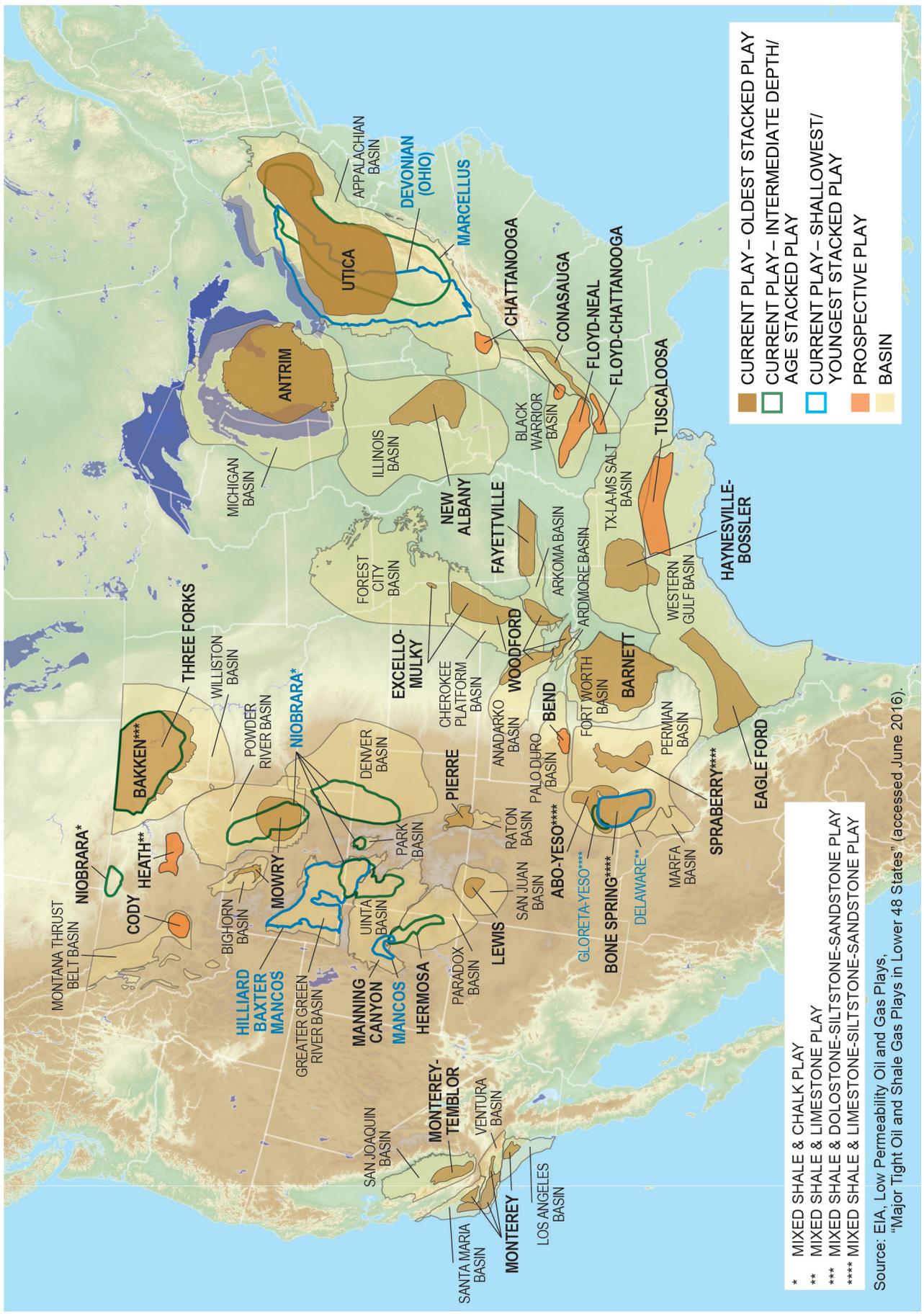
Unconventional reservoirs comprise low-permeability (tight) rocks containing hydrocarbons, rocks that may require horizontal drilling and hydraulic fracturing to enable commercial oil and natural gas production. These reservoirs have permeabilities in the microdarcy<sup>26</sup> range, or lower, and are typically associated with organic-rich shales with total organic carbon by weight percent from 0.5% to more than 10%. However, non-shale rocks—such as chalk, marlstones, tight limestone, dolomites, siltstones or sandstones—can also be classified as unconventional reservoirs. Tight non-shale rocks are often located near, or are interbedded with, organic-rich shales, which serve as source rocks for the hydrocarbons.

Dozens of rock formations that occur in parts of at least 20 states have been identified as having commercial unconventional oil or gas reserves. The Marcellus, Utica, Woodford, and Barnett Formations are examples of prolific gas-producing shales. The Bakken, Wolfcamp, Eagle Ford, and Bone Springs Formations are examples of prolific oil-producing shales. Many of these formations, such as the Eagle Ford and Bakken, produce both oil and natural gas in commercial volumes.

Figure 7-6 shows the locations and extent of Lower 48 U.S. unconventional oil and natural gas plays (does not present Alaska).<sup>27</sup> In

26 A darcy (or darcy unit) is a unit of porous permeability widely used in petroleum engineering and geology. One darcy is equal to the permeability of a medium through which the rate of flow of a fluid having one centipoise viscosity under a pressure gradient of one atmosphere per centimeter would be one cubic centimeter per second per square centimeter cross section.

27 Energy Information Administration, U.S. Department of Energy. (2016). Summary Maps: Shale Gas and Shale Oil Plays, Lower 48 States; June 30, 2016. Washington, DC, 2016.



**Figure 7-6. Unconventional Oil and Natural Gas Plays in the Lower 48 States**

2017, most of the oil and natural gas produced in the United States came from unconventional reservoirs. The EIA estimates that in 2017, about 62% of total U.S. natural gas production was produced from shale formations, and a little more than 50% of total U.S. crude oil was produced from shale and unconventional tight non-shale formations.<sup>28</sup> The proliferation of drilling and production in unconventional reservoirs over the past decade has included them as potential targets for CO<sub>2</sub> storage.

There are several published estimates of CO<sub>2</sub> storage resources in unconventional oil and natural gas reservoirs. In 2005, Nuttall et al. estimated ~28 Gt of CO<sub>2</sub> can be technically stored in portions of the Ohio Shale and New Albany Shale.<sup>29</sup> In 2013, Godec et al. estimated a theoretical maximum CO<sub>2</sub> storage potential of 171 Gt for portions of the Marcellus Shale, although the technically accessible CO<sub>2</sub> storage is estimated at 55 Gt.<sup>30</sup> Tao and Clarens developed a production-based model to estimate theoretical CO<sub>2</sub> storage potentials and reported 10.4 Gt to 18.4 Gt of CO<sub>2</sub> could be stored in the Marcellus Shale by 2030.<sup>31</sup> Godec et al. used estimates of gas in place and economic ultimate recovery reported by the EIA in 2011<sup>32</sup> to estimate the technically accessible CO<sub>2</sub> storage potential of 134 Gt in 19 shale formations in the United States.<sup>33</sup> With respect to CO<sub>2</sub> storage in unconventional tight oil formations, the results of past research

efforts suggest that the storage resource of the Bakken Formation ranges from a minimum of 160 Mt to as high as 3.2 Gt.<sup>34</sup> Though there is a lack of similar storage resource estimates for other tight oil formations, it is reasonable to assume that the Eagle Ford and Wolfcamp Formations in Texas, which are similar to the Bakken Formation, may have similar magnitudes of CO<sub>2</sub> storage capacities.

Although the literature suggests the CO<sub>2</sub> storage potential of unconventional reservoirs may be significant, those estimates are derived from studies based on laboratory experiments, modeling exercises, and unproven correlations of hydrocarbon resource-in-place estimates or production history compared with potential storage resource. There is a lack of knowledge about the fundamental physical and chemical mechanisms controlling many critical aspects of storage in unconventional reservoirs—injectivity, sweep/storage efficiency, and the roles of sorption, wettability, and thermal maturity—and this has precluded them for consideration as primary targets for CO<sub>2</sub> storage. The widespread exploitation of unconventional shale resources is a relatively recent development, within the last 10 to 15 years. Thus, the current level of knowledge about the mechanisms that affect storage of CO<sub>2</sub> in unconventional reservoirs is relatively low when compared with the knowledge of CO<sub>2</sub> injectivity and behavior in conventional reservoirs, which has more than 40 years of history.

To better evaluate the efficacy of CO<sub>2</sub> storage in unconventional reservoirs with tight oil, future research should focus on acquiring a better understanding of the factors that affect long-term injectivity, migration, and storage of CO<sub>2</sub> in different rock types. Both laboratory and modeling-based studies are needed to address questions of fluid and flow behavior in the context of relative permeability because these data are essential for accurately modeling CO<sub>2</sub> behavior in tight formations, especially those that are rich in organic carbon.

28 Energy Information Administration, U.S. Department of Energy. (2017). *Annual Energy Outlook 2017*, <https://www.eia.gov/aeo>, January 5, 2017, Washington, DC.

29 Nuttall, B. C., Eble, C. F., Drahovzal, J. A., and Bustin, M. R. (2005). "Analysis of Devonian black shales in Kentucky for potential carbon dioxide sequestration and enhanced natural gas production," Kentucky Geological Survey Final Report to U.S. Department of Energy.

30 Godec, M., Koperna, G., Petrusak, R., and Oudinot, A. (2013b). "Assessment of factors influencing CO<sub>2</sub> storage capacity and injectivity in eastern U.S. gas shales," GHGT-11, *Energy Procedia*, vol. 37, p. 6644-6655.

31 Tao, Z., and Clarens, A., "Estimating the carbon sequestration capacity of shale formations using methane production rates." *Environmental Science & Technology*, 2013, 47 (19), pp. 11318-11325, doi: 10.1021/es401221j.

32 Energy Information Administration, U.S. Department of Energy, "Review of Engineering Resources: U.S. Shale Gas and Shale Oil Plays," Washington, DC, 2011.

33 Godec, M. L., Jonsson, H., and Basava-Reddi, L. (2013a). "Potential global implications of gas production from shales and coal for geological CO<sub>2</sub> storage." *Energy Procedia*, vol. 37, 6656-6666.

34 Sorensen, J. A., Braunberger, J. R., Liu, G., Smith, S. A., Klenner, R. C. L., Steadman, E. N., and Harju, J. A. (2014). "CO<sub>2</sub> storage and utilization in tight hydrocarbon-bearing formations—a case study of the Bakken Formation in the Williston Basin," *Energy Procedia*, vol. 63, p. 7852-7860.

State and federal resources and permitting policies should emphasize ways to facilitate more CO<sub>2</sub>-based pilot tests in oil and natural gas producing unconventional reservoirs. Because each formation is unique, it is important that tests are conducted in several different plays to capture the effects that variability in reservoir characteristics may have on CO<sub>2</sub> storage in unconventional reservoirs.

### C. Regulations Governing CO<sub>2</sub> Storage in Offshore Formations

The United States offshore consists of submerged lands under the jurisdiction of the coastal states and submerged lands that are under federal jurisdiction, referred to as the Outer Continental Shelf (OCS). The OCS consists of 2.3 billion acres of submerged lands, subsoil, and seabed lying between the seaward extent of the states' submerged lands and the seaward extent of federal jurisdiction. For most areas, federal jurisdiction begins three nautical miles from the shore baseline. However, for Texas and the Gulf Coast of Florida, federal jurisdiction begins nine nautical miles from the baseline, while for Louisiana, federal jurisdiction begins three nautical miles from the baseline. The seaward extent of U.S. federal jurisdiction typically extends to the Exclusive Economic Zone (EEZ), 200 nautical miles from the shore baseline. Beyond the EEZ are international waters.

The storage of CO<sub>2</sub> in the submerged lands within the states' jurisdiction is regulated by the United States EPA UIC program under the U.S. Safe Drinking Water Act of 1974. The Presidential Interagency Task Force on Carbon Capture and Storage examined the existing U.S. regulatory framework for CO<sub>2</sub> storage on the OCS. In 2010, the task force recommended the development of a comprehensive U.S. framework for leasing and regulating sub-seabed CO<sub>2</sub> storage operations on the OCS that addresses the broad range of relevant issues and applies appropriate environmental protections. However, this comprehensive framework has yet to be established. Therefore, the existing regulatory framework is shared across multiple federal agencies, including the Department of the Interior (DOI) and EPA, and may have jurisdictional gaps and redundancies.

### 1. Advantages of Offshore CO<sub>2</sub> Storage

As discussed in the following sections, there are many geologic formations in the offshore environment that are suitable for geologic storage of CO<sub>2</sub>. Very little work has been performed in the breakdown of available storage capacity separating state from federal offshore formations. The extent, thickness, porosity, permeability, and security (suitable cap rock formations) make the injectivity and storage capacity of offshore formations ideal candidates for CO<sub>2</sub> storage. There may be advantages in conducting these operations offshore due to the following factors:

- The offshore environment is managed by state and federal entities instead of the private landowners for onshore environments that can potentially number in the hundreds.
- DOE has conducted, and continues to conduct, extensive research to assess the capacity potential of offshore geologic formations. There are also extensive data from existing oil and natural gas exploration and development—especially in the Gulf of Mexico (GOM) and, to a lesser extent, the Atlantic and Pacific Oceans—as well as other research that contributes to understanding the geologic environment offshore (site characterization, modeling, risk analyses, monitoring protocols).
- Extensive oil and natural gas experience in the GOM provide an extensive knowledge base for CO<sub>2</sub> storage operations in the same environment (e.g., drilling, well installation, decommissioning, analysis of environmental concerns, geologic and geophysical surveying, etc.).
- Some of the existing oil and natural gas infrastructure—platforms, wells, pipelines—could be repurposed for CO<sub>2</sub> storage. Repurposing existing infrastructure for CO<sub>2</sub> storage may be cheaper than decommissioning and removal.
- The offshore environment is distant from populated areas, so there would be no private residences near offshore storage sites.
- There are few or no underground sources of drinking water (USDWs) offshore; salinity in offshore geologic formations is generally more than the EPA limit, so the risk to USDWs is negligible to none.
- The ability to install plume and pressure management (relief wells) solutions. Produced

water from these wells would require disposal in accordance with EPA regulations.

- Pressure from the overlying water column may help to keep the CO<sub>2</sub> in a dense phase, also called a supercritical fluid.
- Geologic and geophysical surveying for monitoring may have fewer impediments due to the lack of structures and landowners.

## 2. Potential Challenges of Offshore CO<sub>2</sub> Storage

There are several challenges to offshore CO<sub>2</sub> storage, such as:

- The lack of clarity regarding jurisdictions and regulatory regime could potentially delay the start of a new project.
- The existing statutory framework is complex and shared across multiple federal agencies and may have jurisdictional gaps and redundancies.
- Long-term liability remains with the operator.
- The potentially high cost of storing CO<sub>2</sub> offshore if there is no access to offshore infrastructure such as oil and natural gas wells.

## 3. How to Enable Offshore CO<sub>2</sub> Storage Projects

There are several actions that would help to enable offshore CO<sub>2</sub> storage projects. The development of a comprehensive federal framework for leasing and regulating sub-seabed CO<sub>2</sub> storage operations on the OCS is vital to the success of these projects. The EPA has an existing legal and regulatory framework for projects in state waters, so clear federal direction on such matters is a necessity. In addition, this OCS legal framework should address long-term liability, which, for other programs such as oil and natural gas, currently remains with the operator. Reuse of infrastructure for CO<sub>2</sub> storage may also be addressed in the legal framework. Currently, oil and natural gas structures must be decommissioned soon after production has ceased. Targeting existing structures and enabling an extension for CO<sub>2</sub> storage use may facilitate project success. Finally, appropriate monitoring should be required throughout the life of the project and designed in a manner that facilitates clear regulatory direction during site closure.

## 4. Offshore CO<sub>2</sub> Injection Projects

According to the Global CCS Institute, in 2017 there were 10 offshore CO<sub>2</sub> injection projects operating, under construction, or undergoing advanced study.<sup>35</sup> Several injection facilities are operational in the Barents Sea and North Sea off the coasts of Norway and the Netherlands. Other operational CO<sub>2</sub> injection projects are offshore Brazil and Japan. Many countries are in the process of advanced study of selected offshore storage sites for development or are conducting detailed evaluation of their offshore storage resources.

The next two sections present some of the offshore storage sites listed in the Global CCS Institute online database that were operating or under construction at that time.

### a. Operating Offshore Projects

*Sleipner.* In 1996, the Sleipner storage project in the Norwegian North Sea was the first large-scale offshore CO<sub>2</sub> storage facility in the world. CO<sub>2</sub> is separated from produced natural gas and reinjected into an offshore sandstone reservoir, the Sleipner gas field. Approximately 0.85 Mtpa of CO<sub>2</sub> has been injected and more than 17 Mt have been injected since the start of the project.

*Snøhvit.* The Snøhvit CO<sub>2</sub> storage site is associated with gas fields in the Barents Sea offshore Norway. CO<sub>2</sub> is captured and processed at a natural gas facility on an island in the north. The captured CO<sub>2</sub> is transported via pipeline to the Snøhvit Field offshore where it is injected into a storage reservoir. More than 4 Mt of CO<sub>2</sub> were stored between 2008 and 2018.

*K12-B Field.* CO<sub>2</sub> is captured at an offshore natural gas production facility and injected into a depleted gas reservoir, the K12-B gas field off the coast of the Netherlands. Injection of CO<sub>2</sub> began in 2004 and cumulative injection to date is estimated at more than 100,000 tonnes.

*Santos Basin.* The Petrobras Santos Basin Pre-Salt Oil Field CCUS Project located off the coast of Brazil has four CO<sub>2</sub> separation and injection systems aboard floating vessels anchored in the

<sup>35</sup> Global CCS Institute, CO<sub>2</sub>RE Database. (2019). <https://www.globalccsinstitute.com/resources/co2re/>.

Santos Basin. The project started operations in 2013. CO<sub>2</sub> is separated on site as a part of natural gas processing and injected into the Lula and Sapinhoá oil fields for CO<sub>2</sub> EOR. In December 2016, the Santos Basin Pre-Salt development reached the milestone of 4 Mt of CO<sub>2</sub> injected into pre-salt fields.

*Tomakomai.* The Tomakomai CCUS Demonstration Project captures CO<sub>2</sub> from a hydrogen production unit at a refinery near Hokkaido, Japan. Approximately 100,000 tonnes of CO<sub>2</sub> per year over a 3-year period are being injected into two near-shore storage sites located 3 to 4 kilometers offshore. Post-injection monitoring will continue for 2 years after CO<sub>2</sub> injection stops.

### **b. Offshore CO<sub>2</sub> Storage Project Under Construction**

*Haifeng Project.* Two carbon capture test facilities will be installed at the Haifeng Power Plant Guangdong in China with offshore storage sites within the Pearl River Mouth Basin of the South China Sea. Total capture capacity for both facilities of the Haifeng Carbon Capture Demonstration Project is estimated at about 70 tonnes per day.

### **c. Offshore CO<sub>2</sub> Storage Options in the Gulf of Mexico**

The states bordering the Gulf of Mexico (Texas, Louisiana, Mississippi, Alabama, Florida) have a high concentration of heavy industry and associated electrical power generation that creates an area of elevated CO<sub>2</sub> emissions. Significant reductions in national emissions could be achieved by focusing on extending onshore storage opportunities to access the large-volume offshore storage reservoirs in this region. The Gulf Coast region offers excellent source-sink matching, proven capture facilities (Air Products, Petra Nova), and developing transportation infrastructure (Denbury’s Green CO<sub>2</sub> pipeline) for CO<sub>2</sub> EOR.

The Gulf of Mexico Basin is one of the largest-volume geologic sinks in the United States. It can accommodate CO<sub>2</sub> from local and regional sources and potentially serve as a storage resource for regions that lack local, suitable geology. As one of the most explored subsurface geologic basins in the world, the geologic and fluid systems of GOM hydrocarbons are well understood.

Geologic Storage Unit	CO <sub>2</sub> Capacity, billion tonnes
Upper Pliocene	105
Lower Pliocene	144
Upper Miocene	199
Lower Miocene	89
Oligocene	21

Source: Carr, D. L., et al. (2011). “Executive summary: Task 15 – NATCARB Atlas Update – CO<sub>2</sub> Sequestration Capacity, Offshore Western Gulf of Mexico,” University of Texas at Austin.

**Table 7-3.** *Western Offshore Gulf of Mexico CO<sub>2</sub> Storage Capacity Estimates (P50 estimate)*

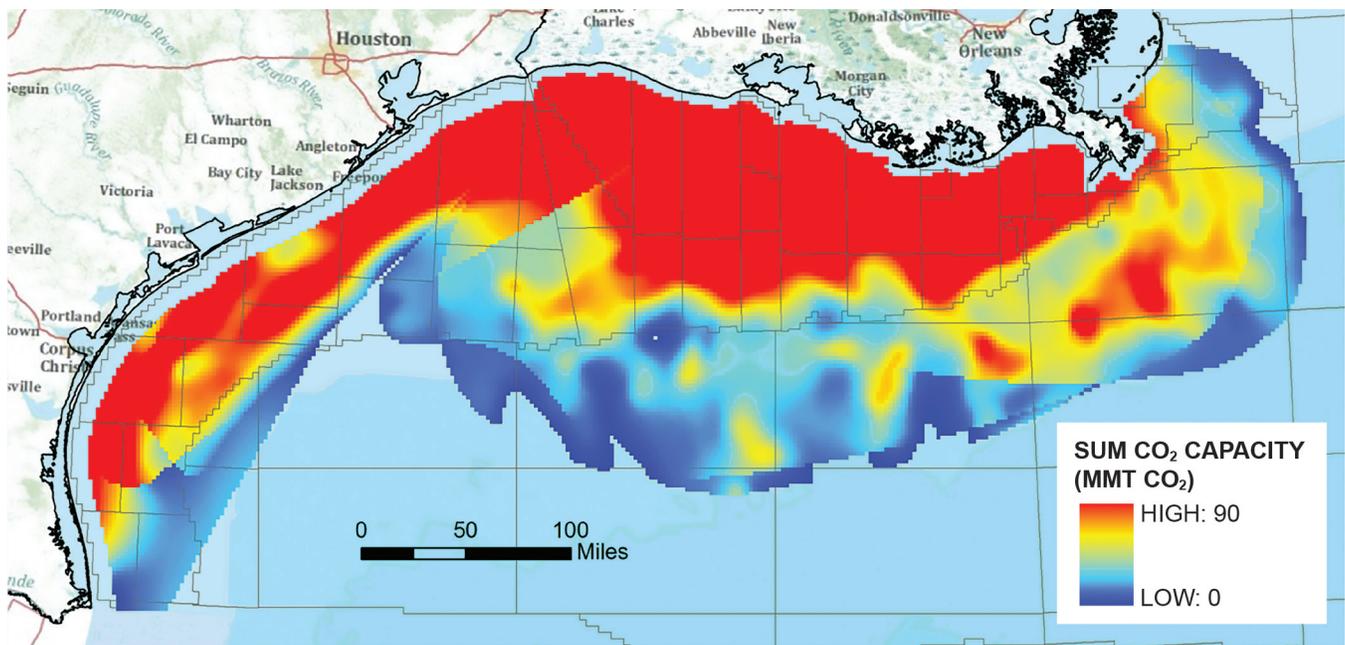
The basin contains multiple geologic storage options, including previously unused porous and permeable sandstone formations that currently contain saline water (saline formations) and depleted oil and natural gas reservoirs from which hydrocarbons have been produced to near economic limits (depleted reservoirs).

Across the GOM region, many studies have been undertaken to characterize the subsurface in various formations. Results from numerous projects in the western GOM can be extrapolated to provide more information on the areas and formations within the greater GOM. Work completed in 2012 estimates that the total CO<sub>2</sub> capacity within the western GOM project area is 559 Gt. Table 7-3 provides estimates of the storage capacity distributed across the five major geologic storage units of the western GOM.<sup>36</sup>

The greatest CO<sub>2</sub> storage capacity in the western GOM lies in Miocene and Pliocene deep saline sandstones. These reservoirs are particularly abundant offshore Louisiana. Substantial capacity, particularly in the Miocene, also occurs along the Texas coast (Figure 7-7).

A 2010 project in the eastern Gulf of Mexico analyzed a 10,000-square mile area offshore Alabama and the western Florida Panhandle and suggested that about 170 Gt of CO<sub>2</sub> could be stored

<sup>36</sup> Carr, D. L., Trevino, R., Meckel, T., Brenton, C., Yang, C., and Miller, E. (2011). “Executive summary: Task 15 – NATCARB Atlas Update – CO<sub>2</sub> Sequestration Capacity, Offshore Western Gulf of Mexico,” University of Texas at Austin, Bureau of Economic Geology, 2 p. GCCC Digital Publication Series #11-24.



Source: Carr, D. L., Trevino, R., Meckel, T., Brenton, C., Yang, C., and Miller, E. (2011). "Executive summary: Task 15 – NATCARB Atlas Update – CO<sub>2</sub> Sequestration Capacity, Offshore Western Gulf of Mexico," University of Texas at Austin, Gulf Coast Carbon Center.

**Figure 7-7. Potential CO<sub>2</sub> Storage in the Western Gulf of Mexico**

in Miocene sandstone, and at least 30 Gt could be stored in deeper Cretaceous formations.<sup>37</sup>

In 2018, the DOE awarded two projects for further study of storage and CO<sub>2</sub> EOR opportunities in the GOM. One project was awarded to the Southern States Energy Board (SSEB) and the other to the University of Texas, Bureau of Economic Geology (BEG). The SSEB project focuses on the eastern GOM while the BEG project focuses on the western GOM. The programs support the DOE's long-term objective to ensure a comprehensive assessment of the potential to implement offshore CO<sub>2</sub> subsea storage in the DOI's Bureau of Ocean Energy Management (BOEM), Outer Continental Shelf Oil, and Gas Leasing Program Planning Areas in the GOM. The goal of this effort is to expand the knowledge base required for commercially viable, secure, long-term, large-scale CO<sub>2</sub> subsea storage, with or without enhanced hydrocarbon recovery. The effort is also intended to support the DOE's long-term objective to ensure a comprehensive assess-

<sup>37</sup> Hills, D. J., and Pashin, J. C. (2010). "Final Report: Southeastern Regional Carbon Sequestration Partnership (SECARB) Phase III – Task 15: Preliminary evaluation of offshore transport and storage of CO<sub>2</sub>," Southern States Energy Board, 16 p., <https://doi.org/10.13140/RG.2.2.33279.66721>.

ment of the potential to implement offshore CO<sub>2</sub> subsea storage in the GOM.

#### **d. Offshore CO<sub>2</sub> Storage Options in the Atlantic Ocean**

Offshore Atlantic CO<sub>2</sub> storage resources have been described by numerous authors, and in 2018 was the focus of two investigations by the Midwest Regional Carbon Sequestration Partnership and the Southeast Regional Carbon Sequestration Partnership, both of which are funded by DOE. Previous investigations<sup>38</sup> have identified

<sup>38</sup> Hovorka, S. D. et al. (2000). "Technical summary: optimal geological environments for carbon dioxide disposal in brine-bearing formations (aquifers) in the United States," University of Texas at Austin, Bureau of Economic Geology, final report prepared for U.S. Department of Energy, National Energy Technology Laboratory, under contract no. DE-AC26-98FT40417, 232 p. GCCC Digital Publication Series #00-01, 203 p., <http://www.beg.utexas.edu/gccc/bookshelf/Final%20Papers/00-01-Final.pdf>.

Midwest Regional Carbon Sequestration Partnership. (2011). "Preliminary characterization of CO<sub>2</sub> sequestration potential in New Jersey and the offshore coastal region," Midwest Regional Carbon Sequestration Partnership, final report prepared for U.S. Department of Energy, National Energy Technology Laboratory, under Cooperative Agreement DE-FC26-05NT42589, 98 p., [https://irp-cdn.multiscreensite.com/5b322158/files/uploaded/njgs\\_carbon\\_sequestration\\_report\\_web.pdf](https://irp-cdn.multiscreensite.com/5b322158/files/uploaded/njgs_carbon_sequestration_report_web.pdf).

U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). National Assessment of Geologic Carbon Dioxide Storage Resources—Results (ver. 1.1, September 2013): U.S. Geological Survey Circular 1386, 41 p., <http://pubs.usgs.gov/circ/1386/>.

CO<sub>2</sub> storage potential in Upper Jurassic and Cretaceous, which are aged saline reservoirs located below the seafloor in state-regulated Atlantic waters and the federal areas of the OCS. In addition to the Jurassic and Cretaceous saline reservoir storage potential in the offshore Atlantic, there is also potential for CO<sub>2</sub> mineralization storage in basaltic rock formations associated with Mesozoic-age rift basins found in offshore areas near New York, New Jersey, Georgia, and Florida.<sup>39</sup>

Offshore Atlantic CO<sub>2</sub> storage resources are largely uninvestigated because geologic information is limited. Fifty-one oil and natural gas exploration wells were drilled in the Atlantic OCS between 1976 and 1983.<sup>40</sup> All wells were abandoned as noncommercial at the time. In 2019, there are no active oil and natural gas leases in the Atlantic area.<sup>41</sup> The Delaware Geological Survey Outer Continental Shelf Core and Sample Repository<sup>42</sup> contains samples from all 51 oil and natural gas wells drilled in the Atlantic OCS offshore regions. Samples include cores, unwashed cuttings, vials containing samples processed for micropaleontology and palynology, and thin sections of core, cuttings, and micropaleontology and palynology splits. In addition, 10 wells were drilled in Florida State waters—Atlantic and Florida Bay—and the Straits of Florida OCS.<sup>43</sup> There is a large quantity of legacy seismic data that can be used to characterize the subsea geology.<sup>44</sup> However, approximately 80% of the mid- and south-Atlantic OCS areas have never been sur-

veyed. Publicly available Atlantic offshore seismic data can be accessed at the National Archive of Marine Seismic Surveys.<sup>45</sup>

The northeast and Mid-Atlantic offshore areas under current evaluation for CO<sub>2</sub> storage resources by the Midwest Regional Carbon Sequestration Partnership include the Georges Bank Basin (New England), Long Island Platform, and Baltimore Canyon Trough (New Jersey, Delaware, Maryland).<sup>46</sup> Storage resources calculations were underway in 2018. The southeast Atlantic areas under investigation by the Southeast Regional Carbon Sequestration Partnership include the Carolina Trough (the Carolinas), Southeast Georgia Embayment (Georgia, Florida), and the Blake Plateau Basin (Georgia, Florida). Southeast Atlantic offshore regional CO<sub>2</sub> storage capacity in Upper Cretaceous strata is estimated to be approximately 32 Gt.<sup>47</sup>

One offshore Atlantic geologic storage project has been proposed off the coast of New Jersey by SCS Energy. The PurGen One project planned to capture CO<sub>2</sub> at a proposed power plant in Linden, New Jersey, and transport 70 miles offshore to an injection site through a 140-mile pipeline.<sup>48</sup> The CO<sub>2</sub> would have been injected into a Cretaceous age saline sandstone formation in the Baltimore Canyon Trough approximately 8,000 feet below the sea floor in a water depth of about 300 feet. The project was canceled in 2011 due to a lack of public support for a new coal-fired power plant.<sup>49</sup>

39 Goldberg, D. S., Kenta, D. V., and Olsen, P. E. (2010). "Potential on-shore and off-shore reservoirs for CO<sub>2</sub> sequestration in Central Atlantic magmatic province basalts," *Proceedings of the National Academy of Sciences*, vol. 107, no. 4, p. 1327–1332, [www.pnas.org/cgi/doi/10.1073/pnas.0913721107](http://www.pnas.org/cgi/doi/10.1073/pnas.0913721107).

40 Bureau of Ocean Energy Management. (2018). Atlantic Oil and Gas Information, Bureau of Ocean Energy Management website, <https://www.boem.gov/Atlantic-Oil-and-Gas-Information/>.

41 Bureau of Ocean Energy Management. (2018).

42 Delaware Geological Survey. (2018). Outer Continental Shelf Core and Sample Repository, Delaware Geological Survey website, <https://www.dgs.udel.edu/projects/outer-continental-shelf-core-and-sample-repository>.

43 Lloyd, J. M., "1994, 1992 and 1993 Florida petroleum production and exploration," Florida Geological Survey, Information Circular No. 110, <http://ufdc.ufl.edu/UF00082065/00005>.

44 International Association of Geophysical Contractors. (2018). "U.S. Atlantic seismic surveys," International Association of Geophysical Contractors, [https://www.iagc.org/uploads/4/5/0/7/45074397/iagc\\_us\\_atlantic\\_seismic\\_surveys\\_final\\_20180420.pdf](https://www.iagc.org/uploads/4/5/0/7/45074397/iagc_us_atlantic_seismic_surveys_final_20180420.pdf).

45 Triezenberg, P. J., Hart, P. E., and Childs, J. R. (2016). "National Archive of Marine Seismic Surveys: A USGS data website of marine seismic reflection data within the U.S. Exclusive Economic Zone," U.S. Geological Survey Data Release, <https://doi.org/10.5066/F7930R7P>.

46 Cumming, L., Gupta, N., Miller, K., Lombardi, C., Goldberg, D., ten Brink, U., Schrage, D., Andreasen, D., and Carter, K. (2017). "Mid-Atlantic U.S. Offshore Carbon Storage Resource Assessment," *Energy Procedia*, vol. 114, p. 4629–4636.

47 Almutairi, K. F., Knapp, C. C., Knapp, J. H., and Terry, D. A. (2017). "Assessment of Upper Cretaceous strata for offshore CO<sub>2</sub> storage, southeastern United States," *Modern Environmental Science and Engineering*, vol. 3, no. 8, p. 532–552, <http://www.academicstar.us/UploadFile/Picture/2018-1/20181301259753.pdf>.

48 Vidas, H., Hugman, B., Chikkatur, A., and Venkatesh, B. (2012). "Analysis of the costs and benefits of CO<sub>2</sub> sequestration on the U.S. Outer Continental Shelf," Bureau of Ocean Energy Management, OCS Study BOEM 2012-100. Prepared under BOEM Contract M10PC00117 by ICF International, 129 p. [https://www.boem.gov/uploadedFiles/BOEM/Oil\\_and\\_Gas\\_Energy\\_Program/Energy\\_Economics/External\\_Studies/OCS%20Sequestration%20Report.pdf](https://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Energy_Economics/External_Studies/OCS%20Sequestration%20Report.pdf).

49 Vidas, H. et al. (2012).

### e. CO<sub>2</sub> Storage Options in the Pacific Ocean

Beneath Pacific waters of the United States offshore California, Oregon, Washington, Alaska, and Hawaii, current prospects for geologic CO<sub>2</sub> storage exist in known oil-producing basins in Southern California and Alaska. Additional opportunities, which were undergoing initial study, may lie in the basalt formations offshore of Washington, Oregon, and potentially Hawaii. These potential offshore storage areas have radically different geologic settings.

Potential targets for CO<sub>2</sub> geologic storage with or without associated CO<sub>2</sub> EOR include the producing oilfields and nonproducing structures (geologic traps) in offshore portions of the Los Angeles, Ventura, and Santa Maria Basins in southern California and the Cook Inlet Basin in Alaska. The onshore parts of the southern California basins were identified as strong prospects for CO<sub>2</sub> EOR in a 2005 study commissioned by DOE,<sup>50</sup> and the offshore part of each basin is geologically like the onshore part. Further, the offshore part of the Ventura Basin is continuous (geologically on-trend) with the onshore part. Although no offshore CO<sub>2</sub> injection projects exist to date, the economic pursuit of CO<sub>2</sub> EOR projects in these basins should yield local knowledge that will support eventual CO<sub>2</sub> injection projects not involving EOR (pure-storage projects). Possible CO<sub>2</sub> geologic storage offshore California would also be able to take advantage of many large CO<sub>2</sub> sources onshore that are nearby, and by the presence of existing drilling- and pipeline-related infrastructure.

Similarly, Alaska has producing offshore oilfields in the Cook Inlet Basin near Anchorage, demonstrating the presence of geologic structures appropriate for CO<sub>2</sub> storage. These structures may be injection targets for CO<sub>2</sub> currently emitted by onshore oil refineries and fossil-fuel power plants located nearby. While potential CCUS targets probably also exist in the Beaufort and Chukchi Seas (notably near Prudhoe Bay), the lack of a CO<sub>2</sub> source and the harsh operating envi-

ronments render these locations infeasible in the near term.

There are no CO<sub>2</sub> geologic storage projects operating in the United States sector of the Pacific. The Pacific exclusive economic zone contains mainly clastic (versus carbonate) reservoir rock of Mesozoic and Cenozoic age. Compared with the Gulf of Mexico and midcontinent, the more active tectonic settings would limit storage prospectively in some areas. However, research on a new storage concept holds promise for secure CO<sub>2</sub> storage beneath the seafloor of large areas offshore Washington, Oregon, and Hawaii. The Cascadia CarbonSAFE Project seeks to inject CO<sub>2</sub> into basaltic rock, where it would eventually mineralize and become permanently stable. Vast areas of basaltic rock occur in ocean basins worldwide as well as in certain onshore areas, such as in Washington State, Russia, and India.

The Cascadia Project site has been extensively drilled and studied for geologic research purposes and has an instrumented observation network through which data are cabled onshore. The project conducted a prefeasibility study to evaluate the technical and nontechnical aspects of collecting and storing 50 Mt of CO<sub>2</sub> at the site. Its Phase I accomplishments include: (1) a compiled evaluation of industrial CO<sub>2</sub> sources and potential modes of transportation in the region, (2) an inventory of existing geophysical and geologic data in the area and evaluation of new data required to further assess storage potential and pre-/post-injection environmental monitoring needs, (3) an initial reservoir model of the potential storage complex, (4) a preliminary analysis of regulatory requirements, stakeholder, and financial needs for the offshore storage complex, and (5) a comprehensive project risk assessment analysis.

Preliminary simulations indicate that injectivity into the basalt rock is high, and that a 50 Mt CO<sub>2</sub> plume injected over a 20-year period will remain within the reservoir area for at least a 50-year period. Lab-based studies show that the injected CO<sub>2</sub> would be fully converted to carbonate minerals in 135 years or less.

<sup>50</sup> Advanced Resources International. (2005). Basin-Oriented Strategies for CO<sub>2</sub>-Enhanced Oil Recovery: California. Prepared for U.S. Department of Energy, April 2005.

## D. CO<sub>2</sub> Storage in Depleted Hydrocarbon Reservoirs

Conventional oil and natural gas reservoirs are porous rock formations, typically sandstones and carbonates, with structural geometries that contain trapped hydrocarbons. Using primary pressure-driven production methods, the production of oil from conventional reservoirs commonly yields 20% to 30% of the original hydrocarbon in place and 60% to 70% of the gas, and an additional 10% to 15% during secondary water flooding. Pore space vacancies generated during reservoir depletion create an ideal storage repository for CO<sub>2</sub> after the field has reached its economic production limit due, in large part, to the formation's well-established structural integrity that trapped buoyant fluids for millennia.

A potential advantage of these sites is that pre-existing infrastructure may exist for storage due to prior field industrialization<sup>51</sup> and may have utility for CO<sub>2</sub> storage operations. There is also the potential for favorable source-sink matching with proximal stationary CO<sub>2</sub>-emitting sources. Furthermore, oilfields with remaining oil after completion of primary and secondary recovery operations may be candidates for EOR methods, including CO<sub>2</sub> EOR. CO<sub>2</sub> storage can also take place adjacent to, above, or below depleted or active hydrocarbon reservoirs, realizing additional storage capacity while utilizing existing oilfield infrastructure.<sup>52</sup> Incidental CO<sub>2</sub> trapping associated with CO<sub>2</sub> EOR is described in Chapter 8, "CO<sub>2</sub> Enhanced Oil Recovery." CO<sub>2</sub> storage after the conclusion of CO<sub>2</sub> EOR operations may also present a good storage opportunity.

### 1. Advantages of CO<sub>2</sub> Storage in Depleted Hydrocarbon Reservoirs

The advantages to storing CO<sub>2</sub> in depleted hydrocarbon reservoirs include: (1) well-known and characterized reservoir properties, (2) established trapping and sealing mechanisms of buoyant fluids in structural and stratigraphic traps, (3) potential trapping of CO<sub>2</sub> in un-swept

(remaining) oil and water rather than remaining as a separate phase, (4) reservoirs with weak water drive<sup>53</sup> may deplete pressure to further enhance storage capacity,<sup>54</sup> and (5) use of existing oilfield infrastructure, such as wells. These advantages enable more reliable and robust predictions of the long-term fate of the CO<sub>2</sub> in proven reservoirs, enhance storage capacity in amenable reservoirs, and reduce the overall costs of storage. Furthermore, CO<sub>2</sub> storage operations may face less opposition from stakeholders in regions with a history of hydrocarbon production.

An estimated 190 to 230 Gt of CO<sub>2</sub> storage capacity has been established in U.S. oil and natural gas reservoirs.<sup>55</sup> These fields are found in basins that cover an extensive portion of the onshore United States, from the Appalachian Basin in the east, the Permian and Gulf Basins in the south, and the Sacramento Basin in the west. Figure 7-8 shows the distribution of natural gas fields within those basins. Additional opportunities for storage may potentially exist after CO<sub>2</sub> EOR operations have ceased by offering a residual CO<sub>2</sub> saturation. This may act to enhance CO<sub>2</sub> injectivity and, in conjunction with further pressure depletion, enable improved storage capacity.

### 2. Challenges of CO<sub>2</sub> Storage in Depleted Hydrocarbon Reservoirs

There are several technical challenges to using depleted oil fields for CO<sub>2</sub> storage. First, during the process of primary and secondary oil production, oil fields undergo large changes in stress that have irreversible effects on the rock properties. Not only does this permanently reduce the pore volume of the rock, but it can also make the rocks more susceptible to hydraulic fracturing.<sup>56</sup>

<sup>51</sup> DOE/NETL Carbon Storage Atlas (2015).

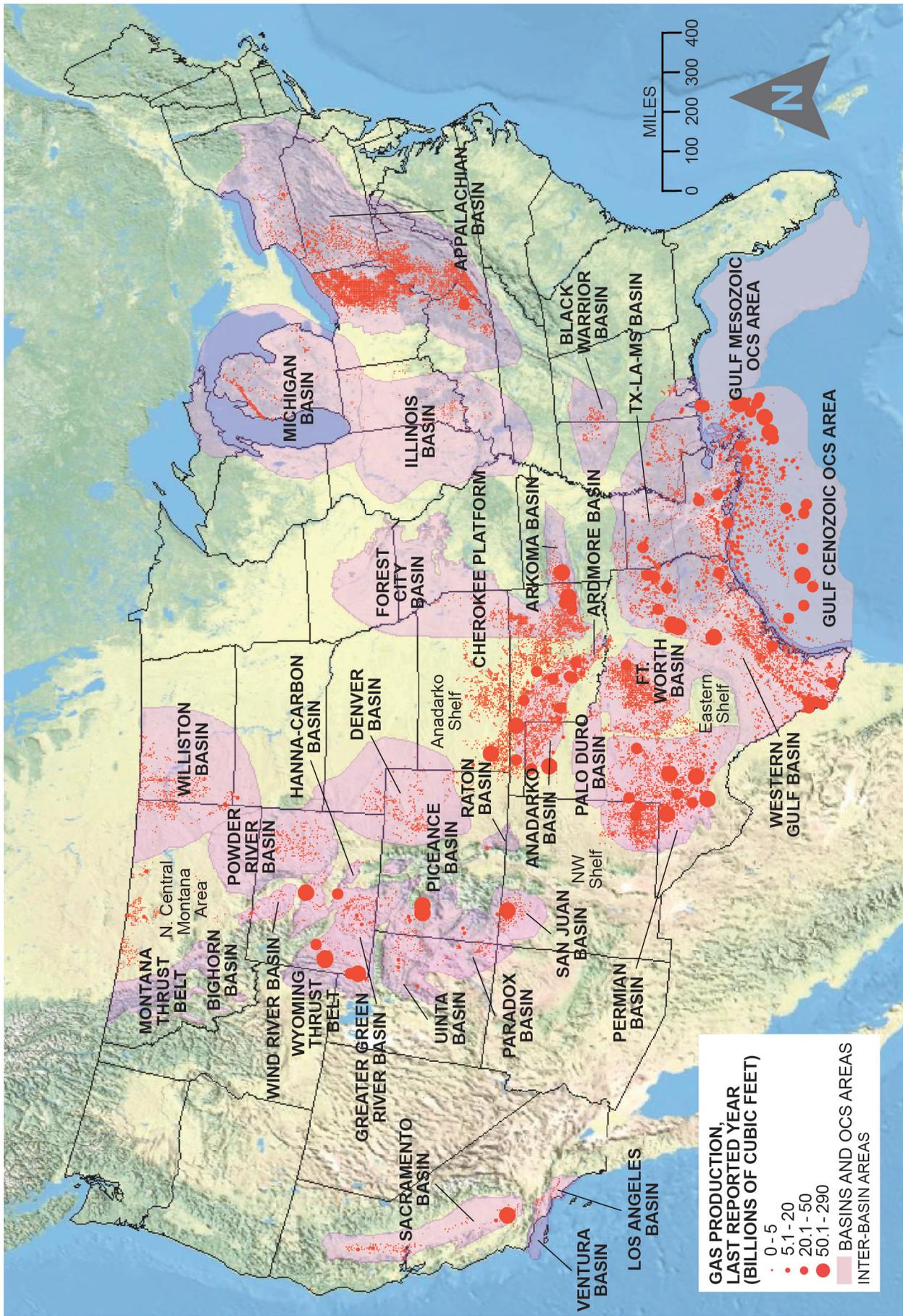
<sup>52</sup> Esposito, R. A., Pashin, J. C., and Walsh, P. M., "Citronelle Dome: A Giant Opportunity for Multi-Zone Carbon Storage and Enhanced Oil Recovery in the Mississippi Interior Salt Basin of Alabama," *Environmental Geosciences*, 2008, 15(2), 1-10.

<sup>53</sup> A weak water drive describes a reservoir where support from the surrounding aquifer is limited, generally resulting in significant pressure depletion during hydrocarbon production.

<sup>54</sup> Hovorka, S. D. (2010). *EOR as Sequestration-Geoscience Perspective*, Bureau of Economic Geology, Jackson School of Geosciences, University of Texas at Austin.

<sup>55</sup> DOE/NETL Carbon Storage Atlas (2015).

<sup>56</sup> Chan, A. W., and Zoback, M. D. (2002). "Deformation Analysis in Reservoir Space (DARS): A Simple Formalism for Prediction of Reservoir Deformation with Depletion," in *Proceedings of the SPE/ISRM Rock Mechanics in Petroleum Engineering Conference*.



Source: EIA Maps, based on data from USGS, updated April 2009.

**Figure 7-8.** Distribution of Natural Gas Production in the Lower 48 States

Second, hydrocarbons are produced from oil and natural gas reservoirs through wells that penetrate numerous stratigraphic intervals in the subsurface. These penetrations provide potential conduits for the leakage of CO<sub>2</sub> out of the reservoir, necessitating stringent well monitoring protocols. Any reactivation of hydrocarbon extraction activities in the field may result in additional leakage risks through newly drilled wells. And hydrocarbon well completion and stimulation practices may impact cap rock integrity. Although it is unlikely, there is also the potential that the cap rock may endure compaction damage when the reservoir's pore fluid pressure is decreased during production.<sup>57</sup>

Third, when injecting CO<sub>2</sub> into depleted reservoirs, proper modeling of multiphase flows in wells is needed to ensure that Joule-Thomson effects<sup>58</sup> in the wellbore do not lead to extreme cold temperatures that form ice and could damage the well or cement.

Legal issues also pose a challenge to storage in depleted oil and natural gas fields because hydrocarbon production leases do not address CO<sub>2</sub> injection or storage without the primary objective of hydrocarbon production. Injecting CO<sub>2</sub> into a depleted oil reservoir negates or complicates any future recovery of remaining oil resources if new technology or economic conditions might warrant such a scenario. Once hydrocarbon production ceases for a specified period, a lease agreement between the operator and oil or gas owner is typically terminated. CO<sub>2</sub> storage, therefore, necessitates developing a new contractual arrangement, and a primary challenge with CCUS is the ownership of subsurface pore space. Law reviews suggest it is likely that landowners will retain ownership of the pore space.<sup>59</sup> There-

fore, any new framework may require a suite of new criteria to resolve the challenges facing CO<sub>2</sub> storage in depleted hydrocarbon reservoirs.

Storing additional CO<sub>2</sub> in an oil field after the completion of CO<sub>2</sub> EOR operations also poses some unique challenges. CO<sub>2</sub>, and often water, are injected into the oil field during CO<sub>2</sub> EOR, and oil, natural gas, water, and CO<sub>2</sub> are produced. If the injection is optimized for CO<sub>2</sub> storage, any CO<sub>2</sub> produced will be recycled for reinjection into the reservoir. The average CO<sub>2</sub> saturations in the flooded portion of the oil field can be 20% or more. This contrasts with the average saturation of CO<sub>2</sub> of 5% to 8% in many CO<sub>2</sub> storage formations at the end of CO<sub>2</sub> injection. At the end of CO<sub>2</sub> EOR operations, if CO<sub>2</sub> continues to be injected into the same wells without removing brine or oil, the CO<sub>2</sub> may be pushed outside the boundaries of the oil field. This will require precise reservoir engineering to avoid this scenario by accessing any remaining storage space.

## E. Other Storage Options

This section briefly describes other available geologic CO<sub>2</sub> storage options that have been investigated and tested at various scales. Two options are discussed here:

1. CO<sub>2</sub> injection and storage in deep subsurface coal beds; for example, during enhanced coal-bed methane recovery
2. CO<sub>2</sub> mineralization to form solid carbonate phases in basaltic and ultramafic rocks and mine tailings.

Compared to the CO<sub>2</sub> storage resources that are available in deep saline formations and depleted oil and natural gas reservoirs in sedimentary basins, storage options in subsurface coal beds may be of local interest in areas where coal-bearing rocks occur. Conversely, vast CO<sub>2</sub> mineralization storage volumes may be available in onshore and offshore basalts. It should be noted that while some limited R&D is being performed in these alternative storage options, no demonstration- or commercial-scale projects have been conducted to determine the long-term feasibility of these storage options. Both technical and regulatory issues remain as barriers for commercial-scale development.

<sup>57</sup> IEA Greenhouse Gas R&D Programme (IEA GHG), "CO<sub>2</sub> storage in Depleted Gas Fields," 2009/01, June 2009.

<sup>58</sup> Joule-Thomson effect describes the temperature change of a real gas or liquid when it is forced through a valve (or wellbore or perforation) while keeping it insulated so that no heat is exchanged with the environment.

<sup>59</sup> Duncan, I. J., Anderson, S., and Nicot, J. P. (2009). "Pore space ownership issues for CO<sub>2</sub> sequestration in the US." *Energy Procedia*, vol. 1, p. 4427-4431. GHGT-9, <https://www.sciencedirect.com/science/article/pii/S1876610209009011?via%3Dihub#aep-bibliography-id13>.

Burt, S. L. (2016). "Who Owns the Right to Store Gas: A Survey of Pore Space Ownership in U.S. Jurisdictions," <http://www.duqlawblogs.org/joule/wp-content/uploads/2016/04/Burt-Article-with-Burt-Edits-4.28.pdf>.

## 1. CO<sub>2</sub> Storage in Deep Subsurface Coal Beds

Coal is a rock composed primarily of preserved organic material. CO<sub>2</sub> injected into a coal bed rapidly absorbs into the organic material in coal and is trapped by a process called adsorption trapping. Deep coal beds, beds that may not be mined for economic or technical limitations, can be used to store CO<sub>2</sub>. The target coal beds must have enough permeability to allow the injected CO<sub>2</sub> to reach far into the coal to be absorbed onto the organic material. However, laboratory research and field tests have shown that CO<sub>2</sub> injection into coal can decrease permeability and adversely impact CO<sub>2</sub> injectivity rates. The injected CO<sub>2</sub> does not need to be in the supercritical (dense phase) state for it to be adsorbed by coal, allowing CO<sub>2</sub> storage in coals to take place at shallower depths (at least 650 feet or 200 meters deep) than storage in oil and natural gas reservoirs or deep saline formations (at least 3,000 feet or 1 km deep). An added benefit to storing CO<sub>2</sub> in coal beds is that the injected CO<sub>2</sub> may displace methane that naturally occurs in most coal beds (CO<sub>2</sub>-enhanced coalbed methane recovery). CO<sub>2</sub>-enhanced coalbed methane recovery is analogous to CO<sub>2</sub> EOR in that the revenue from the sale of the produced hydrocarbons can help to offset the cost of CO<sub>2</sub> storage.

DOE's National Energy Technology Laboratory (2015)<sup>60</sup> estimated that the United States may have a median CO<sub>2</sub> storage capacity of 80 billion Mt in deep coal beds. There have been multiple CO<sub>2</sub>-enhanced Coalbed Methane Recovery pilots and demonstration tests conducted worldwide.<sup>61</sup> However, according to the Global CCS Institute

online database, there are no planned or active coal-bed CO<sub>2</sub> storage projects. This is due in part to the technical challenges encountered during pilot projects performed in the southeastern United States.

## 2. CO<sub>2</sub> Mineralization in Basaltic and Ultramafic Rocks

Geologic storage of CO<sub>2</sub> is possible by injecting it into subsurface basaltic and ultramafic rocks or by reacting CO<sub>2</sub>-bearing fluid or gas with mine tailings rich in mafic minerals.<sup>62,63</sup> According to a 2018 report by NASEM, CO<sub>2</sub> mineralization may occur in one of three ways:

- Ex situ carbon mineralization—Solid mineral reactants are transported to a site of CO<sub>2</sub> capture then react with fluid or gas rich in CO<sub>2</sub>
- Surficial carbon mineralization—CO<sub>2</sub>-bearing fluid or gas reacts with mine tailings, alkaline industrial wastes, or sedimentary formations rich in reactive rock fragments, all with a high proportion of reactive surface area
- In situ carbon mineralization—CO<sub>2</sub>-bearing fluids are circulated through suitable reactive rock formations at depth.

With ex-situ or surficial mineralization, CO<sub>2</sub> is stored through reaction with crushed material at the surface to form a stable carbonate. Examples include captured CO<sub>2</sub> reacting with mafic and ultramafic mine tailings or industrial byproducts such as fly ash, cement kiln dust, and iron and steel slag.<sup>64</sup>

During in situ pilot studies of CO<sub>2</sub> injection into subsurface mafic rocks in Iceland and southeastern Washington, rapid subsurface carbonate

<sup>60</sup> DOE/NETL Carbon Storage Atlas (2015).

<sup>61</sup> Sloss, L. L. (2015). "Potential for enhanced coalbed methane recovery," International Energy Association Clean Coal Centre, 41 p., <https://www.usea.org/sites/default/files/media/Potential%20for%20Enhanced%20coalbed%20methane%20recovery%20-ccc252.pdf>.

<sup>62</sup> Kelemen, P. B., Matter, J., Streit, E. E., Rudge, J. F., Curry, W. B., and Blusztajn, J. (2011). "Rates and mechanisms of mineral carbonation in peridotite: Natural Processes and Recipes for Enhanced, in situ CO<sub>2</sub> Capture and Storage," *Annual Review of Earth and Planetary Sciences*, v. 39, no. 1, p. 545–576, <https://doi.org/10.1146/annurev-earth-092010-152509>.

<sup>63</sup> Mafic minerals are those that are rich in magnesium and iron. Suitable rocks for large-scale CO<sub>2</sub> mineralization include the ultramafic rocks dunite, peridotite, and serpentinite and the mafic rock basalt. See Blondes, M. S., Merrill, M. D., Anderson, S. T., and DeVera, C. A. (2019). "Carbon dioxide mineralization feasibility in the United States," U.S. Geological Survey Scientific Investigations Report 2018–5079, <https://doi.org/10.3133/sir20185079>.

<sup>64</sup> Kirchofer, A., Becker, A., Brandt, A., and Wilcox, J. (2013). "CO<sub>2</sub> Mitigation potential of mineral carbonation with industrial alkalinity sources in the United States," *Environmental Science & Technology*, v. 47, no. 13, p. 7548–7554, <https://doi.org/10.1021/es4003982>.

Power, I. M., McCutcheon, J., Harrison, A. L., Wilson, S. A., Dipple, G. M., Kelly, S., Southam, C., and Southam, G. (2014). "Strategizing Carbon-Neutral Mines: A Case for Pilot Projects," *Minerals*, v. 4, no. 2, p. 399–436, <https://doi.org/10.3390/min4020399>.

mineralization has been shown to occur within 2 years after injection of CO<sub>2</sub>.<sup>65</sup> In 2009, researchers began conducting a prefeasibility study for storing 50 Mt of CO<sub>2</sub> in oceanic basalts in the Cascadia Basin, offshore Washington, and British Columbia.<sup>66</sup>

A detailed assessment of CO<sub>2</sub> storage resources associated with mineralization has not been completed for the United States. However, there are significant mafic basalts and ultramafic rock volumes that could be used for the mineralization process. Suitable ex-situ and surficial carbon mineralization targets include asbestos or other ultramafic mine tailings, and in situ targets include ultramafic rocks on the East and West Coasts, the Columbia River Basalts in the Pacific Northwest, and the Midcontinent Rift Zone basalts in the midcontinent. Hawaii has volumes of potential in situ target reservoir rocks that could be used to mitigate local CO<sub>2</sub> emissions.<sup>67</sup> The 2018 NASEM report described the CO<sub>2</sub> mineralization potential in basaltic and ultramafic rocks as essentially unlimited and recommended increased funding for research to better quantify the CO<sub>2</sub> mineralization resources of the United States.

## IV. ENABLING AT-SCALE DEPLOYMENT OF CO<sub>2</sub> STORAGE

### A. Build on Other Efforts

The DOE's National Risk Assessment Partnership (NRAP) initiative is focused on developing the science base and associated toolsets to elucidate the behavior of CO<sub>2</sub> storage sites despite

geologic uncertainty. Many decisions for a commercial CO<sub>2</sub> storage operation must be made before the detailed behavior of the site can be probed empirically during injection operations. These decisions relate to estimation of storage capacity, strategies to optimize storage, design of an effective and economic monitoring plan, and plan for site closure.

Utilizing resources and expertise across the DOE national lab complex, the NRAP initiative has been using a unique hybrid of physics-based simulations and empirical models to reveal how CO<sub>2</sub> storage systems are likely to perform over a range of variable conditions. The initiative is grounding these predictive tools in targeted experiments and field-based observations to quantify key processes associated with storage-system performance.

Several important findings relevant to commercial deployment of CO<sub>2</sub> storage have emerged from the NRAP initiative:

- If an adequate geologic model is available, the primary factors that affect how a storage site will respond to fluid injection and extraction can be predicted by using existing methods for predicting fluid flow, geochemical reactions, and geomechanical responses. Prediction accuracy is further improved after initial CO<sub>2</sub> plume monitoring data are available and used to calibrate the model. This is not meant to imply that the rate and direction of CO<sub>2</sub> plume movement in a reservoir can be predicted precisely using conventional approaches, or that all subsurface processes are completely understood or are fully embodied in conventional simulation methods. Rather, it acknowledges, for example, that a Darcy's law-based prediction of plume evolution has enough physics to inform a decision on CO<sub>2</sub> plume evolution, particularly in a statistical sense. Hence, NRAP has relied heavily on a battery of existing predictive simulators, extending them in new ways to address specific risk-related challenges.
- The major uncertainties in predictions of CO<sub>2</sub> plume evolution—which stem from variability in subsurface characteristics and the associated model parameters—can be bound at levels low enough to make better decisions than

65 Matter, J. M., et al. (2016). "Rapid carbon mineralization for permanent disposal of anthropogenic carbon dioxide emissions," *Science*, v. 352, no. 6291, p. 1312–1314, <https://doi.org/10.1126/science.aad8132>.

McGrail, B. P., Schaef, H. T., Spane, F. A., Cliff, J. B., Qafoku, O., Horner, J. A., Thompson, C. J., Owen, A. T., and Sullivan, C. E. (2017). "Field validation of supercritical CO<sub>2</sub> reactivity with basalts," *Environmental Science & Technology Letters*, v. 4, no. 1, p. 6–10, <https://doi.org/10.1021/acs.estlett.6b00387>.

66 Goldberg, D., and Slagle, A. L. (2009). "A global assessment of deep-sea basalt sites for carbon sequestration," *Energy Procedia*, vol. 1, no. 1, p. 3675–3682, <https://doi.org/10.1016/j.egypro.2009.02.165>.

67 Blondes, M. S., Merrill, M. D., Anderson, S. T., and DeVera, C. A. (2019). "Carbon dioxide mineralization feasibility in the United States," U.S. Geological Survey Scientific Investigations Report 2018–5079, <https://doi.org/10.3133/sir20185079>.

in the absence of this probabilistic information. A major challenge is to have grids<sup>68</sup> with fine enough resolution to capture the influence of thin, high-permeability layers.

- Post-injection monitoring plans that vary in time and location based on the evolving risk at the storage site are as effective and significantly less costly than static monitoring plans based on a fixed time. Assessing case studies over a range of site characteristics and operational conditions, the NRAP initiative has found that the risk-related behavior of a storage site changes significantly during the 10-year time period after injection stops, meaning that effective monitoring plans can vary spatially and temporally.
- The most likely leakage-related scenarios result in small impacts. Further, with respect to aquifer impacts, many modeled leakages result in changes to groundwater that are below detection limits—in other words, below a no-impact threshold. Exceptions to this would be large leaks that could be readily detected during the injection phase of an operation.
- Leakage pathways in wellbores completed with Portland-based cements are likely to self-seal over time due to a combination of geochemical and geomechanical processes. However, other leakage pathways in wellbores could come from fatigue in the continuous cement and casing caused by the CO<sub>2</sub> injection mode, thermodynamic effects, etc.

## B. Stakeholder Acceptance of Storage Security

Public support for CO<sub>2</sub> storage projects is of paramount importance at every level, from the local community to elected regional and state officials, and nongovernmental organizations interested in energy and climate solutions.<sup>69</sup> Community

<sup>68</sup> A reservoir model can be used to represent the physical space of the reservoir by defining an array of discrete cells, delineated by a grid that may be regular or irregular. This grid array of cells is usually three-dimensional, although 1D and 2D models are sometimes used.

<sup>69</sup> De Coninck, H., and Benson, S. M. (2014). “Carbon Dioxide Capture and Storage: Issues and Prospects.” *Annual Review of Environment and Resources*, 39, 243–270.

communications, outreach, and education can set the tone for the life of the project. Additional information about the importance of stakeholder engagement is discussed in Chapter 4, “Building Stakeholder Confidence,” in Volume II of this report.

## C. Subsurface Pressure Management

The amount of CO<sub>2</sub> that needs to be sequestered for CCUS to have a meaningful impact on reducing emission could cause widespread pressure increases in the subsurface. Injecting large quantities of fluids (wastewater or CO<sub>2</sub>) into the subsurface increases reservoir pressure, which could potentially compromise CO<sub>2</sub> containment, cause induced seismicity risk, and have a significant economic impact on a CCUS project. It is recognized that excessively large pressure increases in a reservoir might create new fractures or reactivate preexisting ones with the associated risk of induced seismicity or leakage. Furthermore, it can also limit the total capacity of the reservoir or the amount of CO<sub>2</sub> that can be injected per well.<sup>70</sup>

Extracting brine from a conventional storage formation is one potential option as a pressure management strategy that could reduce pressure

<sup>70</sup> Rutqvist, J. (2012). “The Geomechanics of CO<sub>2</sub> Storage in Deep Sedimentary Formations.” *Geotechnical and Geological Engineering*, 30, 525–551, <https://doi.org/10.1007/s10706-011-9491-0>.

Zoback, M. D., and Gorelick, S. M. (2012). “Earthquake triggering and carbon sequestration.” *Proceedings of the National Academy of Sciences*, 109 (26): 10164–10168, doi: 10.1073/pnas.1202473109.

Chiaromonte, L., White, J. A., and Trainor-Guitton, W. (2015). “Probabilistic geomechanical analysis of compartmentalization at the Snøhvit CO<sub>2</sub> sequestration project.” *Journal of Geophysical Research Solid Earth*, 120, 1195–209, doi: 10.1002/2014JB011376.

Buscheck, T. A., Bielicki, J. M., Edmunds, T. A., Hao, Y., Sun, Y., Randolph, J. B., and Saar, M. O. (2016). “Multifluid geo-energy systems: Using geologic CO<sub>2</sub> storage for geothermal energy production and grid-scale energy storage in sedimentary basins,” *Geosphere*, 12 (3): 678–696, doi: <https://doi.org/10.1130/GES01207.1>.

Jahediesfanjani, H., Warwick, P. D., and Anderson, S. T. (2017). “3D Pressure-limited approach to model and estimate CO<sub>2</sub> injection and storage capacity: saline Mount Simon Formation.” *Greenhouse Gases: Science and Technology*, 7, 1080–1096, doi: 10.1002/ghg.1701.

Jahediesfanjani, H., Warwick, P. D., and Anderson, S. T. (2018). “Improving pressure-limited CO<sub>2</sub> storage capacity in saline formations by means of brine extraction.” *International Journal of Greenhouse Gas Control*, vol. 88, 299–310, <https://doi.org/10.1016/j.ijggc.2019.06.009>.

buildup and might also help manage CO<sub>2</sub> plume migration and aerial extent—which impacts monitoring, verification, and accounting costs—and eventually provide desalinated or treated water for diverse uses.<sup>71</sup>

Pressure management has been implemented as part of the Gorgon project in Western Australia. Reservoir engineers identified that the number of potential CO<sub>2</sub> injection wells suggested for the project could be reduced by incorporating an active reservoir pressure management system. This involves extracting formation water from the Dupuy Formation at locations within pressure communication of the injection area but outside the range of the forecast CO<sub>2</sub> plume migration. The project includes four water production wells that will pump water from the Dupuy Formation using electrical submersible pumps. To reduce environmental impacts, that produced water will be reinjected into the overlying Barrow Group by two water disposal wells. It is expected that this system will produce approximately 60,000 to 80,000 barrels of water per day from the Dupuy Formation. That off-take rate was included in the reservoir simulations used to determine the CO<sub>2</sub> injection well count.<sup>72</sup>

71 Buscheck, T. A., Bielicki, J. M., Edmunds, T. A., Hao, Y., Sun, Y., Randolph, J. B., and Saar, M. O. (2016). “Multifluid geo-energy systems: Using geologic CO<sub>2</sub> storage for geothermal energy production and grid-scale energy storage in sedimentary basins.” *Geosphere*, 12 (3): 678–696. doi: <https://doi.org/10.1130/GES01207.1>.

Buscheck, T. A., Sun, Y. W., Hao, Y., Wolery, T. J., Bourcier, W., Tompson, A. F. B., et al. (2011). “Combining brine extraction, desalination, and residual-brine reinjection with CO<sub>2</sub> storage in saline formations: Implications for Pressure Management, Capacity, and Risk Mitigation.” *Science Direct*, 4, 4283–4290, <http://dx.doi.org/10.1016/j.egypro.2011.02.378>.

Klapperich, R., Cowan, R., Gorecki, C. D., Bremer, J. M., Holubnyak, Y., Kalenze, N. S., Knudsen, D. J., Saini, D., Botnen, L. S., LaBonte, J. L., Stepan, D. J., Steadman, E. N., Harju, J. A., Basava-Reddi, L., and McNemar, A. (2013). “IEAGHG Investigation of Extraction of Formation Water from CO<sub>2</sub> Storage.” *Energy Procedia*, 37, 2479–2486, doi: [10.1016/j.egypro.2013.06.129](https://doi.org/10.1016/j.egypro.2013.06.129).

Newmark, R. L., Friedmann, S. J., and Carroll, S. A. (2010). “Water Challenges for Geologic Carbon Capture and Sequestration.” *Environmental Management*, 45, 651–661, <https://doi.org/10.1007/s00267-010-9434-1>.

Hunter, K., Bielicki, J. M., Middleton, R., Stauffer, P., Pawar, R., Harp, D., and Martinez, D. (2017). “Integrated CO<sub>2</sub> storage and brine extraction.” *Energy Procedia*, 114, 6331–6336, <https://doi.org/10.1016/j.egypro.2017.03.1769>.

72 Trupp, M., Frontczak, J., and Torkington, J., “The Gorgon CO<sub>2</sub> Injection Project – 2012 Update,” *Energy Procedia*, vol. 37, 2013, p. 6237–6247, <http://www.sciencedirect.com/science/article/pii/S1876610213007959>.

However, in large-scale CCUS projects the magnitude of brine extraction necessary might lead to considerable water management and economic challenges. Aside from the Gorgon Project, for which CO<sub>2</sub> injection and storage started in August 2019, knowledge about the benefits and challenges of brine extraction comes from research studies and a few pilot projects, such as the DOE Brine Extraction Storage Test effort, which will extract brine for pressure management and test various treatment options to produce water suitable for surface use.<sup>73</sup>

Several strategies have been proposed regarding brine extraction as an approach for pressure management. These strategies include preproduction of brine before injecting CO<sub>2</sub> to increase reservoir capacity,<sup>74</sup> simultaneous brine extraction and CO<sub>2</sub> injection to maintain decreased pressure,<sup>75</sup> and brine extraction at specific critical locations (i.e., near faults) to minimize seismicity risk.<sup>76</sup>

73 Office of Fossil Energy, “Energy Department Selects Projects to Demonstrate Feasibility of Producing Usable Water from CO<sub>2</sub> Storage Sites,” <https://www.energy.gov/fe/articles/energy-department-selects-projects-demonstrate-feasibility-producing-usable-water-co2>. (Accessed January 15, 2019).

74 Buscheck, T. A., Bielicki, J. M., White, J. A., Sun, Y., Hao, Y., Bourcier, W. L., Carroll S. A., and Aines, R. D. (2016). “Pre-injection brine production in CO<sub>2</sub> storage reservoirs: An approach to augment the development, operation, and performance of CCS while generating water.” *International Journal of Greenhouse Gas Control* 54: 499–512.

75 Bergmo, P. E. S., Grimstad, A.-A., and Lindeberg, E., “Simultaneous CO<sub>2</sub> injection and water production to optimize aquifer storage capacity.” *International Journal of Greenhouse Gas Control* 2011;5: 555–64.

Buscheck, T. A., Sun, Y., Hao, Y., Wolery, T. J., Bourcier, W. L., Tompson, A. F. B., Jones, E. D., Friedmann S. J., and Aines, R. D. (2011). “Combining brine extraction, desalination, and residual-brine reinjection with CO<sub>2</sub> storage in saline formations: Implications for pressure management, capacity, and risk mitigation,” *Energy Procedia*, vol. 4, p. 4283–4290.

Buscheck, T. A., Sun, Y., Chen, M., Hao, Y., Wolery, T. J., Bourcier, W. L., et al. “Active CO<sub>2</sub> reservoir management for carbon storage: Analysis of operational strategies to relieve pressure buildup and improve injectivity.” *International Journal of Greenhouse Gas Control* 2012 6:230–45. doi:[10.1016/j.ijggc.2011.11.007](https://doi.org/10.1016/j.ijggc.2011.11.007).

Bourcier W. L., Wolery, T. J., Wolfe, T., Haussmann, C., Buscheck, T. A., and Aines, R. D., “A preliminary cost and engineering estimate for desalinating produced formation water associated with carbon dioxide capture and storage.” *International Journal of Greenhouse Gas Control* 2011; 5: 1319–28. doi:[10.1016/j.ijggc.2011.06.001](https://doi.org/10.1016/j.ijggc.2011.06.001).

76 Kroll, K. A., Buscheck, T. A., White, J. A., and Richards-Dinger, K. B. (2018). “Active Pressure Management as a Tool to Reduce Induced Seismicity,” Seismological Society of America, 2018 Seismology of the Americas Meeting, 14–17 May 2018, Miami, Florida.

Similarly, several uses for the produced brine have been proposed that include desalination and treatment, reinjection in overlying or underlying saline formations, or disposing of it in the sea. Identified options for the treated brine include offsetting water requirements for CO<sub>2</sub> capture, using for power plant cooling water, and using in agriculture or industrial settings, such as for lithium extraction.<sup>77</sup>

Challenges associated with the use of brine extraction techniques include the cost of additional wells for brine extraction, brine disposal, and the cost of desalination and treatment that will be essential for surface usage. However, this impact could be offset by additional revenue from brine reuse. Some studies suggest that for certain locations, almost the same brine volume as the injected CO<sub>2</sub> volume needs to be removed to prevent induced seismicity.<sup>78</sup> If this much brine were reinjected back into the subsurface in a seismically vulnerable area, this in and of itself would create concerns.

In summary, while brine extraction may be necessary or desirable for some locations, significant challenges remain, and more research is needed to assess the viability of brine extraction as a means of pressure management.

#### **D. Matching a Source to a Sink**

CO<sub>2</sub> source-sink matching involves pairing a stationary CO<sub>2</sub> emitter with a potential reservoir. This includes geologic formations such as depleted oil or gas reservoirs, potentially unmixable coal seams, saline formations, and unconventional resource reservoirs. In practice, potential storage sites will have limitations on both CO<sub>2</sub> storage capacity and injection rate that are subject to geological characteristics. Factors considered for appropriate pairing include distance from source to sink, availability of existing CO<sub>2</sub> pipelines to transport supercritical CO<sub>2</sub>, depth and geologic attributes of the sink, population distribution near proposed projects, proximity to parks or public lands, and vulnerability of the overlying environment. It is also important

to consider social factors—population distribution, community sentiment, private and municipal water supplies, regional environment, and protected areas. Utilizing regional storage hubs could provide value with multiple sources accessing one regionally significant sink.

The main issue associated with source-sink matching is the cost of transport to the storage site. Models for source-sink matching include integer linear programs, vector data-based multi-source technics, raster data-based single-source, and sink-matching models. Based on such models, a decision support system is developed that considers the influence of several factors: reservoir capacity, geometry, injection pressure, sealing formation attributes, vertical proximity of USDWs, potential for enhanced oil or gas recovery, complex terrain factors (such as the slope of the terrain, bypassing urban areas and national parks, and crossing rivers, railways, or highways to find the lowest cost pathway between source and sink), population density, ownership, and social and political data.

Applying Big Data Analytics tools to decrease storage costs and de-risk a project requires highly detailed databases in a data structure that fits the computational models. NETL has developed the National Carbon Sequestration Database to facilitate the use of analytics to aid in source-sink matching. NETL has also funded programs to advance these analytical tools. The potential for reducing the overall costs of CCUS can be significant with respect to the identification of geologic sinks in proximity to the CO<sub>2</sub> emitting sources, which have been identified in several of the DOE's CarbonSAFE and RCSP program projects. Continuing and expanding these efforts and providing potential operators access to these data will have help to accelerate the development of CCUS projects. Furthermore, the Internal Revenue Service Section 45Q tax credit has considerable influence on the cost effectiveness of CCUS projects where source-sink matching is concerned.

#### **E. Pore Space Legal Rights**

Before injecting CO<sub>2</sub> for geologic storage, the operator must own the pore space, have permission from the owner, or otherwise have the

<sup>77</sup> See footnote 71.

<sup>78</sup> Kroll et al. (2018).

right to use the pore space. Therefore, the project developer will have to acquire the authorization to access and use pore space to avoid liability for subsurface trespass and nuisance before a geologic CO<sub>2</sub> storage field can be developed. A detailed discussion related to pore space and the challenges related to the development of a commercial-scale storage project is provided in Chapter 3, “Policy, Regulatory, and Legal Enablers,” in Volume II of this report.

## F. State Primacy

The EPA regulates subsurface injection to protect USDWs via the Safe Drinking Water Act’s UIC program. In 2010, the EPA developed UIC Class VI rules for wells used to inject CO<sub>2</sub> specifically for the purpose of long-term geologic storage. These Class VI rules cover items such as CO<sub>2</sub> injection and site characterization, well permitting, well construction and operational standards, testing, plugging, recordkeeping, corrective action, emergency and remedial response, closure and post-closure care, and associated financial assurance requirements.

The Class VI regulations can be implemented by the EPA or adopted by states, territories, or tribes as the primary enforcement authority. Designation of this authority outside of the EPA is called primacy. Primacy authorizes a state, territory, or tribe to implement regulatory responsibilities associated with the UIC program. States must apply for primacy and be granted authority through EPA review and rulemaking.

In 2013, North Dakota became the first state to seek primacy from the EPA for the Class VI UIC program and was granted authority in July 2017. The North Dakota Industrial Commission amended its own carbon sequestration rules to align with the federal regulations. In 2019, the only other state perusing primacy for the Class VI program was Wyoming. The state of Wyoming filed its application for Class VI primacy with the EPA in Region 8 on January 2018 through the Wyoming Department of Environmental Quality. As of April 2019, that application is still pending, and no additional information is available.

The benefits of state primacy for the Class VI UIC program are numerous. However, because

there is little funding available from the EPA for state UIC programs, there is limited incentive for states to take primacy for the Class VI program. It would be helpful if states had access to information about the benefits of receiving Class VI primacy, the process and experience of states that have primacy for other well classes, and financial support for developing a Class VI primacy application and implementing the program for commercial projects.

A more detailed discussion of state primacy and its implications is discussed in Chapter 3.

## V. CROSSCUTTING ISSUES FOR CO<sub>2</sub> EOR AND CO<sub>2</sub> STORAGE

Storage projects can be broadly divided into two types. Dedicated CO<sub>2</sub> storage involves the underground injection of anthropogenic CO<sub>2</sub> (from industrial sources) for the sole purpose of GHG mitigation. Incidental or associated storage occurs when CO<sub>2</sub> is injected for other purposes, such as CO<sub>2</sub> EOR.

It is important to note that in the United States, less than 30% of the CO<sub>2</sub> used for CO<sub>2</sub> EOR is from anthropogenic sources; the remainder comes from natural sources. There have been more than 100 commercial CO<sub>2</sub> EOR projects in the United States since the 1970s, and experience has shown that CO<sub>2</sub> EOR produces incremental oil and permanently traps CO<sub>2</sub>.

In contrast, dedicated CO<sub>2</sub> storage is a relatively nascent industry with a few commercial-scale projects operating around the world—those storing more than approximately 0.5 Mtpa of CO<sub>2</sub>. Although incidental or associated storage is a physical consequence of EOR, operators of such sites might not seek recognition of GHG mitigation benefits because of various economic, regulatory, or legal factors. CO<sub>2</sub> EOR projects are driven by the economic benefit of producing oil that may not be recoverable by primary production methods. Historically, the trapping of CO<sub>2</sub> has been a result of the CO<sub>2</sub> EOR process, rather than an explicit objective of the CO<sub>2</sub> EOR process. During CO<sub>2</sub> EOR operations, CO<sub>2</sub> is produced with the recovered oil, separated and purified, and reinjected for additional oil recovery. The result

of this closed-loop CO<sub>2</sub> system is that associated storage infrastructure requirements tend to be more complex than those for dedicated storage, which does not include oil production.

Although the primary goals of dedicated and associated storage may be different, the two do share several key crosscutting aspects. Both dedicated and associated storage result in the secure storage of anthropogenic CO<sub>2</sub>, providing mitigation for GHG emissions. Both require similar geologic conditions, engineering approaches, monitoring technologies, and social license to operate. With respect to geologic conditions, both types of storage require reservoir rocks with enough injectivity and storage capacity to support commercial-scale CO<sub>2</sub> injection. Thick, sealing rocks are also necessary for both types of storage to ensure that the injected CO<sub>2</sub> does not migrate outside of the permitted zone. Subsurface engineering approaches and requirements for drilling, operating, and maintaining wells are similar and the technologies and protocols used are essentially interchangeable. Many surface infrastructure elements—pipelines, compressors, wellheads, and Supervisory Control and Data Systems—are also largely the same, regardless of whether they are for associated or dedicated storage. Monitoring the injection of CO<sub>2</sub> and its subsequent movement in the subsurface is an essential component of both CO<sub>2</sub> EOR and dedicated storage projects.

While general principles and technologies are common to dedicated and associated storage, site-specific factors will always impart unique qualities to each project. Dedicated storage sites have significantly fewer well penetrations compared with associated storage via CO<sub>2</sub> EOR. It is also important to note that there are differences between CO<sub>2</sub> storage and EOR categories, particularly with respect to monitoring and tax incentives. CO<sub>2</sub> EOR operators tend to refer to monitoring as reservoir surveillance, while dedicated storage operators call it monitoring, verification, and accounting. Regardless of the terminology, the technologies used to determine the disposition of the injected CO<sub>2</sub> are largely the same.

There are, however, striking differences between associated and dedicated storage in terms of the

regulatory requirements for monitoring and how the data generated by those activities are used. For EOR operators, the primary purpose of gathering monitoring data is to better understand the efficiency of their operation, typically in terms of CO<sub>2</sub> utilization rates measured in units of CO<sub>2</sub> (either purchased or injected) per unit of oil. Monitoring for dedicated storage places more emphasis on determining the areal extent and geometry of the CO<sub>2</sub> plume and detecting any movement of CO<sub>2</sub> out of the designated storage zone. Both CO<sub>2</sub> EOR and dedicated storage projects use monitoring technologies, such as well-head pressure gauges, to ensure safe operations and reduce operational risk.

In addition to sharing monitoring approaches and technologies, there are also important crosscutting aspects between saline storage and EOR that result from operations in stacked reservoirs. Operations in stacked reservoirs occur when CO<sub>2</sub> is injected into saline reservoirs that are above or below oil reservoirs. The surface infrastructure constructed for development of the oil field, especially that which is used for CO<sub>2</sub> EOR, can be used for saline storage projects in reservoirs that are above or below the oil reservoir. The geological characterization that has been used to develop the oil resources (data from well logs and seismic surveys) will give a saline storage project a detailed understanding of critical properties such as reservoir depth, thickness, and architecture at the earliest stages of the project. This will always be the case for saline resources above an oil reservoir, and sometimes the case for saline resources below an oil reservoir, although there are typically fewer wells that penetrate below any given oil reservoir. Dedicated storage projects in saline reservoirs below oil fields must contend with challenges from drilling through the oil reservoir, including zones of abnormal pressure conditions (higher or lower pressures than expected) and ensuring that well drilling and completion operations do not inadvertently damage the oil reservoir. There are also challenges when distinguishing multiple overlapping CO<sub>2</sub> plumes in zones above or below an active CO<sub>2</sub> EOR project. Advancements in monitoring technologies, including improvements in geophysical and acoustic data acquisition and processing, are needed to address those challenges.

In some instances, a dedicated storage project may be conducted in the same rock formation as the oil reservoir, but in a water-saturated zone that is geologically down-dip from the main area of oil saturation, that is in the reservoir's "water leg." Like saline storage resources above and below an oil reservoir, dedicated storage in the water leg of an oil reservoir can benefit from, and dovetail with, the infrastructure, characterization, and monitoring elements of a nearby CO<sub>2</sub> EOR project. However, migrating the injected CO<sub>2</sub> from the water leg into the oil reservoir will complicate CO<sub>2</sub> monitoring and accounting for both the dedicated storage project and the CO<sub>2</sub> EOR project, which can lead to complications in the certification of storage by government agencies and qualification of Section 45Q tax credits. CO<sub>2</sub> storage in stacked reservoirs and water leg reservoirs may also face challenges from pore space ownership and mineral lease issues. Clarifying existing state and federal policies and regulations and, in some cases, new legislative directives that address the crosscutting aspects of dedicated storage and CO<sub>2</sub> EOR, may be necessary.

## VI. RESEARCH AND DEVELOPMENT NEEDS

Ramping up global CO<sub>2</sub> storage in geologic formations to a scale of gigatonnes per year is an enormous task. For example, increasing global storage of CO<sub>2</sub> to 1 Gt/year—a scale equivalent to approximately 40% of United States stationary source CO<sub>2</sub> emissions—would require a fifteenfold increase beyond the CO<sub>2</sub> EOR and storage operations that exist around the world in 2019. There is already a broad level of technical expertise from more than 20 years of CO<sub>2</sub> storage experience and 100 years of oil and natural gas operations to increase the number of geologic storage projects in oil and natural gas reservoirs and saline formations.

However, for global CO<sub>2</sub> storage to expand to a 1 Gt CO<sub>2</sub>/year level and beyond, much more intensive use of storage resources will be necessary, requiring better information to assess risks, to inform site characterization and source-sink matching, and providing assurances that permanent storage will be safe and secure. The 2018 NASEM report on CO<sub>2</sub> Removal and Secure

Sequestration and the International Initiative Mission Innovation Workshop on CO<sub>2</sub> Capture and Sequestration, provide comprehensive assessments of research needs. In this chapter, the focus is on those R&D needs that will support the rapid scale-up of CO<sub>2</sub> storage in geologic formations in the United States.

Globally, there is a significant amount of experience from the previously cited CO<sub>2</sub> storage projects injecting at the scale of 1 Mt/year, and there are several other projects at a smaller scale. There are distinct challenges to rapidly increasing the number of large-scale CCUS projects in the United States, such as how the presence of multiple CO<sub>2</sub> storage projects in a single basin might interact with each other through overlapping pressure buildups and CO<sub>2</sub> plume comingling and the continued research about the commercial viability of using unconventional formations (shale, basalt) for large-scale CO<sub>2</sub> injections.

Figure 7-9 presents a sketch providing a spatial comparison to illustrate the extent to which injecting CO<sub>2</sub> into a saline formation causes pressure buildup in the formation and the area surrounding it. The individual footprint of a CO<sub>2</sub> plume in a saline formation may extend 30 km<sup>2</sup> to 300 km<sup>2</sup>, but the area in which pressure buildup occurs is even larger. If there are multiple CO<sub>2</sub> injection projects within the same saline formation, the pressure buildup from the projects will be additive, extending the buildup over a larger area.

Given the need to address the challenges, research priorities include:

- Increasing the efficiency of site characterization and selection methods
- Increasing pore space utilization by improving confidence in CO<sub>2</sub> plume immobilization mechanisms and accelerating their speed in immobilizing CO<sub>2</sub>
- Improving coupled models for optimizing and predicting CO<sub>2</sub> flow and transport, geomechanics, and geochemical reactions, including leveraging capabilities in the oil and natural gas industry
- Lowering the cost of monitoring and developing new monitoring technologies

- Quantifying and managing the risks of induced seismicity
- Investigating the feasibility of Mt/year storage in alternatives to sandstone and carbonate reservoirs, including ultramafic rocks (basalt) and low-permeability rocks (shale)
- Conducting social sciences research for improving stakeholder engagement and informing the public about the need, opportunity, risks, and benefits of CO<sub>2</sub> storage in geologic formations.

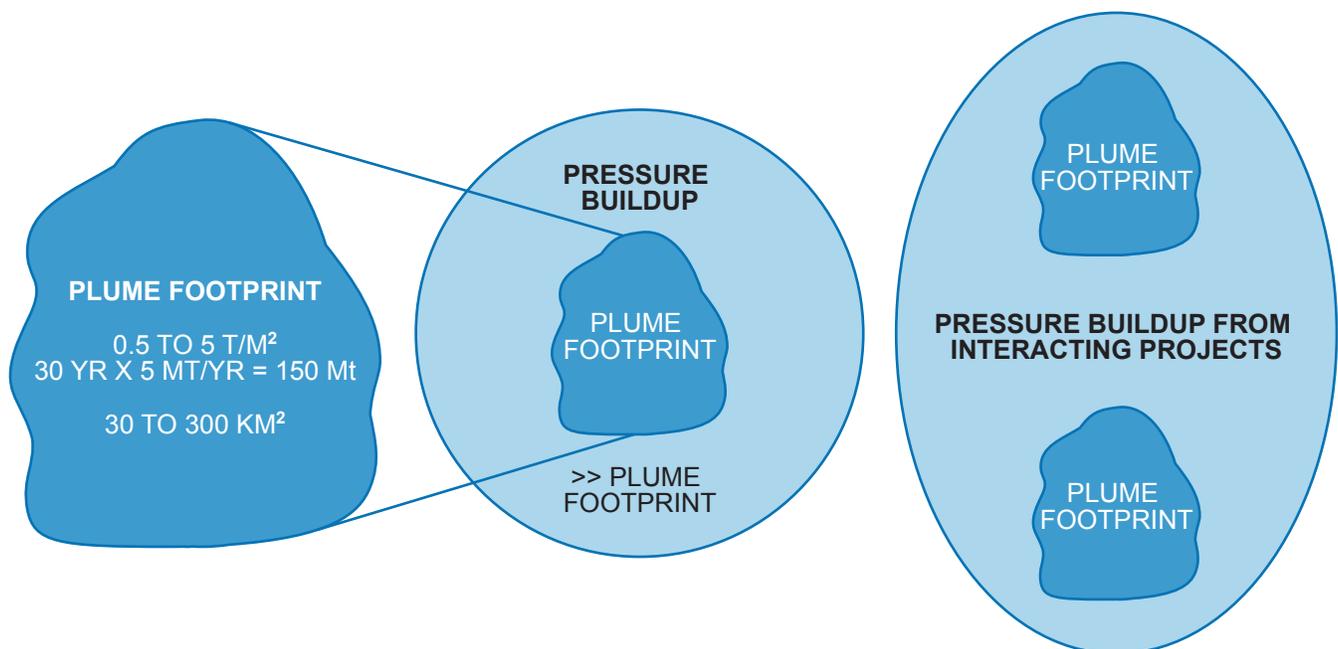
These research activities will address many of the practical and financial challenges facing operators who are contemplating new large-scale storage projects. Table 7-4 details how the proposed research activities address these needs. Current R&D programs address the needs of fundamental storage science, storage site characterization and drilling, and pilot- and demonstration-scale CO<sub>2</sub> injection projects. Combining additional pilot and demonstration projects with CO<sub>2</sub> storage R&D will help the nascent CO<sub>2</sub> storage industry achieve at-scale deployment in the United States. These projects would also establish valuable infrastructure during the R&D phase that could then be used for commercial-scale deployment.

It is recommended that an increase of the current DOE R&D budget for geologic storage by \$400 million per year for the next 10 years could be allocated as follows:

- \$80 million to the Regional Initiative to Accelerate CCUS Deployment (for a total appropriation of \$100 million per year)
- \$100 million for characterization of geologic storage formations, including offshore, that have scale potential through the CarbonSAFE program or similar initiatives (for a total appropriation of \$150 million per year)
- \$220 million per year to enable field-scale projects that collect data and geologic samples used to advance the science of long-term CO<sub>2</sub> storage security.

These R&D activities also play a critical role in increasing the industrial workforce needed to carry out these activities.<sup>79</sup> These projects should also provide a testing opportunity for monitoring and predictive modeling of CO<sub>2</sub> in the subsurface at-scale.

<sup>79</sup> National Academies of Sciences, Engineering, and Medicine. (2018). *Negative Emissions Technologies and Reliable Sequestration: A Research Agenda*. Washington, DC: The National Academies Press, 356 p., <https://org/10.17226/25259>.



**Figure 7-9.** Spatial Comparison of a CO<sub>2</sub> Plume and Area of Pressure Buildup it Affects

R&D Needs	Project Phase	Site Characterization, Selection, and Engineering	Operations	Closure and Post-Closure Site Care
Reliable site characterization (seals, faults, trapping, heterogeneity)		<ul style="list-style-type: none"> <li>Confidence in seal integrity</li> <li>Accurate assessment of plume footprint</li> <li>Injection well design and optimization</li> </ul>		<ul style="list-style-type: none"> <li>Accurate site geologic model for post-injection CO<sub>2</sub> migration and pressure recovery</li> </ul>
Lower costs of monitoring		<ul style="list-style-type: none"> <li>Risk-based monitoring design tailored to site specific requirements</li> </ul>	<ul style="list-style-type: none"> <li>Cost optimal monitoring and awareness of plume footprint and pressure buildup</li> </ul>	<ul style="list-style-type: none"> <li>Monitoring to support risk-based duration of post-closure site care</li> </ul>
Plume immobilization, quantification, and acceleration		<ul style="list-style-type: none"> <li>Accurate assessment of plume footprint</li> <li>Optimize injection and operational design to limit footprint</li> </ul>	<ul style="list-style-type: none"> <li>Reduced CO<sub>2</sub> footprint lowers monitoring costs and project risks</li> </ul>	<ul style="list-style-type: none"> <li>Shorten the time to CO<sub>2</sub> immobilization</li> <li>Reduce duration of post-closure site care</li> </ul>
Risks to groundwater		<ul style="list-style-type: none"> <li>Assess and mitigate risks to groundwater from CO<sub>2</sub> and brine leakage</li> <li>Contingency plans for unanticipated leakage</li> </ul>	<ul style="list-style-type: none"> <li>Mitigation plans for unexpected leakage</li> </ul>	<ul style="list-style-type: none"> <li>Confidence in long-term groundwater protection</li> </ul>
Induced seismicity science and mitigation		<ul style="list-style-type: none"> <li>Avoid or mitigate seismic risks through site selection and project design</li> <li>Contingency plans for unexpected seismicity</li> </ul>	<ul style="list-style-type: none"> <li>Mitigation plan for unexpected induced seismicity</li> </ul>	
Better simulation models for lifecycle plume migration and trapping		<ul style="list-style-type: none"> <li>Accurate assessment of plume footprint</li> <li>Optimize injection and operational design to limit CO<sub>2</sub> footprint and pressure buildup</li> </ul>	<ul style="list-style-type: none"> <li>Rapid and accurate model calibration with monitoring data</li> <li>Update operational design based on monitoring data</li> </ul>	<ul style="list-style-type: none"> <li>Accurate prediction of post-closure CO<sub>2</sub> migration and pressure recovery to support risk-based site closure</li> </ul>
Alternatives to conventional storage (shale, basalt, coal)		<ul style="list-style-type: none"> <li>Expand range of storage options for improved source-sink matching</li> </ul>	<ul style="list-style-type: none"> <li>Operational parameters optimized to characteristics of unconventional reservoirs</li> </ul>	<ul style="list-style-type: none"> <li>Risk-based post-injection monitoring and site care</li> </ul>

**Table 7-4.** Research Needs for Different Phases of a Geologic CO<sub>2</sub> Storage Project

## VII. PRIORITIES FOR ACHIEVING AT-SCALE DEPLOYMENT OF CCUS

This study has identified three phases projected to occur over a 25-year period to achieve at-scale deployment of CCUS in the United States—activation phase, expansion phase, and at-scale phase.

Each phase is defined by the primary actions that need to occur within a relative timeframe, including near-term, mid-term, and long-term priorities. The phases and their priorities are based on the abatement cost curve analysis presented in Chapter 2, “CCUS Supply Chains and Economics,” in Volume II of this report.

## A. Near-Term Priorities for the Activation Phase

### 1. Increased Funding for R&D

As of October 2019, there were 19 large-scale CCUS projects operating around the world with a total storage capacity of about 32 Mtpa of CO<sub>2</sub>. Ten of these projects are in the United States with a total storage capacity of 25 Mtpa. Enabling an additional 25 Mtpa to 40 Mtpa of CO<sub>2</sub> storage during the next 5 to 7 years of the CCUS activation phase would require doubling the current R&D budget for geologic sequestration to about \$250 million/year short-term research priorities include:

- Increasing the efficiency of site characterization and selection methods
- Increasing pore space utilization by improving confidence in CO<sub>2</sub> plume immobilization mechanisms and accelerating their speed in immobilizing CO<sub>2</sub>
- Improving coupled models for optimizing and predicting CO<sub>2</sub> flow and transport, geomechanics, and geochemical reactions, including leveraging capabilities in the oil and natural gas industry
- Lowering the cost of monitoring and developing new monitoring technologies
- Quantifying and managing the risks of induced seismicity
- Investigating the feasibility of Mt/year storage in alternatives to sandstone and carbonate reservoirs, including ultramafic rocks (basalt) and low-permeability rocks (shale)
- Conducting social sciences research for improving stakeholder engagement and informing the public about the need, opportunity, risks, and benefits of CO<sub>2</sub> storage in geologic formations.

Table 7-4 details how the proposed research activities address the needs of each phase of a geologic storage project to illustrate how it will benefit industry operators. For example, new methods for using the available pore space more efficiently will reduce the cost of characterizing a site by limiting the area that must be

characterized. During the operational phase of a project, high-reliability and low-cost monitoring programs that are targeted to the largest project-specific risks will increase stakeholder confidence that groundwater resources are protected, and site-workers and the public are safe. For the closure and post-closure phase, proven models for predicting the long-term behavior of stored CO<sub>2</sub> will help to shorten the post-closure site care period by providing tools for the operator to demonstrate that USDWs would not be endangered after the injection period stops. In addition to providing valuable knowledge, university-based research programs will ensure a pipeline of qualified talent to increase the workforce capacity that will be needed to support the scale-up of CO<sub>2</sub> capture and storage operations.

### 2. Class VI Permit Reform

Some aspects of the Class VI regulations for CO<sub>2</sub> storage are problematic for increased adoption of CCUS. Improvements and reform of Class VI regulations include optimizing permit process efficiency to shorten the time it takes to obtain a permit by improving the level of coordination between the permit applicant and the regulatory authority that grants the permit. Other potential improvements to the regulatory process include adopting risk-based monitoring approaches, clarifying that site closure is allowed when drinking water aquifers are no longer endangered, providing flexibility for CO<sub>2</sub> plume tracking requirements, adopting a risk-based approach for the post-closure monitoring period, subdividing the area of review into two regions (one for the CO<sub>2</sub> plume and one for the pressure buildup), and developing an approach for defining the area of review for naturally over-pressured storage reservoirs. These issues are discussed in more detail in Chapter 3.

### 3. Section 45Q Tax Reform and Clarification

The FUTURE Act passed as part of the 2018 budget appropriation provides a tax credit of \$50/tonne (by 2026) of CO<sub>2</sub> stored in a saline formation. The Section 45Q tax credit has the potential to dramatically increase deployment of CO<sub>2</sub> storage in the United States. However, several

issues must be addressed, including: clarifying what is required to demonstrate “secure geologic storage;” establishing regulations for recapturing the credit if the CO<sub>2</sub> ceases to be properly captured, disposed of, or reused as a tertiary injectant; and providing developers with clarity, either through regulation or guidance, on what constitutes “beginning of construction.” Section 45Q is discussed in more detail in Chapter 3.

#### **4. Access to Onshore Federal Lands**

One of the hurdles for owners of stationary sources of CO<sub>2</sub> who want to implement commercial-scale geologic storage is securing a sufficiently large tract of land and associated subsurface pore space to develop a geologic storage site. Federal lands present a unique opportunity to achieve this due to single ownership of large, continuous acreage, a large portion of which contains formations with ample CO<sub>2</sub> storage capacity. The estimated CO<sub>2</sub> storage capacity beneath federal lands ranges between 126 and 375 Gt. New regulations and processes are needed to enable use of federal lands for CO<sub>2</sub> storage. These issues are also discussed further in Chapter 3.

### **B. Medium-Term Priorities for the Expansion Phase**

#### **1. R&D and Workforce Capacity**

The expansion phase could enable an additional 75 to 85 Mtpa of CO<sub>2</sub> storage within the next 15 years. Research that addresses medium-term priorities will be needed to address the gaps in knowledge that emerge as the CCUS industry begins to grow. Continued advances in data science, machine learning, advanced sensing, and other innovations are likely to benefit CO<sub>2</sub> geologic storage. Research programs at universities will increase the workforce of engineers, geoscientists, and other disciplines with the level of technical expertise needed to support the increasing number of CO<sub>2</sub> storage projects and supporting infrastructure that will be developed during the 15 years of the Expansion Phase.

#### **2. State Primacy**

The EPA and, in some cases the states, have the permitting authority and oversight of the Class

VI program. Approval of primary enforcement responsibility to the states is termed primacy. States either incorporate the federal standards by reference or develop their own state regulations for approval by rule through the EPA. There are many benefits to establishing state primacy, which includes aligning state objectives, improved coordination of the Class VI program, leveraging state experience, and establishing a business advantage. However, because there is minimal funding available from the EPA (as appropriated by Congress) for all state UIC programs, there is little funding incentive for states to take primacy for the Class VI program. It would be beneficial if funding was increased and used to develop a Class VI primacy application and program for commercial-scale projects. It would also be helpful if states had access to information about the benefits of receiving Class VI primacy, the process, and experience of states that have primacy for other well classes.

#### **3. Pore Space Legal Rights**

Before injecting CO<sub>2</sub> into the subsurface for geologic storage, the operator must own the pore space, have permission from the owner, or have the right to use the pore space. The laws concerning property rights are a basic concern of state law rather than federal law. Pore space ownership is rooted in the ad coelum doctrine where “the ownership of land may be divided horizontally, vertically or otherwise either above or below the ground.” The issue of pore space legal rights is complicated by the fact that for a large CO<sub>2</sub> storage project, the CO<sub>2</sub> plume may extend over hundreds of square miles, and the pressure buildup extends over an even larger area. For large projects, including those identified as CO<sub>2</sub> storage hubs where multiple property and pore space owners are likely to be involved in the process of acquiring pore spaces rights, resolving issues related to property rights and competing uses of the subsurface could have a large impact on the commercial viability of CO<sub>2</sub> storage. It is recommended that federal and state governments coordinate to establish a process for permitting the access and use of pore space for geologic storage projects on privately owned lands.

## C. Long-Term Priorities for the At-Scale Phase

### 1. Access to Conventional Offshore Formations

The at-scale phase increases total U.S. storage capacity from CCUS to approximately 500 Mtpa within the next 25 years. This level of storage would require access to conventional offshore formation. The OCS includes submerged lands under the jurisdiction of the federal government and coastal states. Some of the benefits of offshore CO<sub>2</sub> storage include the fact that it is managed by state and federal entities rather than private landowners. There is also extensive oil and natural gas experience in the Gulf of Mexico that is transferable to CO<sub>2</sub> storage, and existing oil and natural gas infrastructure could be repurposed for CO<sub>2</sub> storage. Offshore storage also puts few or no USDWs at risk, and pressure management of the formation by extracting brine is likely easier. Finally, geologic and geophysical surveying for monitoring offshore storage may be subject

to fewer impediments due to the lack of numerous structures and landowners. Offshore storage could be enabled by requirements for monitoring for the life of the project but designed in a manner that facilitates the ease of site closure after storage operations terminate.

### 2. Continued R&D and Workforce Capacity Development

Like the expansion phase, research that addresses the long-term priorities of the at-scale phase will be needed to address the gaps in knowledge that emerge as the CCUS industry continues to grow. Continued advances in data science, machine learning, advanced sensing, and other innovations are likely to benefit CO<sub>2</sub> geologic storage. Research programs at universities will increase the workforce of engineers, geoscientists, and other disciplines with the level of technical expertise needed to support the increasing number of CO<sub>2</sub> storage projects and supporting infrastructure that will be developed during the 25 years of the at-scale phase.

